BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of Its Distribution Resources Plan	))))	Application No. 15-07-_____ (Filed July 1, 2015)

APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) FOR APPROVAL OF ITS DISTRIBUTION RESOURCES PLAN

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Dated: **July 1, 2015**

APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) FOR APPROVAL OF ITS DISTRIBUTION RESOURCES PLAN

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I. INTRODUCTION

In compliance with Pub. Utilities Code § 769(b) and the *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning,*[1] and pursuant to Rules 2.1 of the Commission's Rules of Practice and Procedure, Southern California Edison Company (SCE) is respectfully submitting this Application seeking approval of its Distribution Resources Plan (DRP).

II. BACKGROUND

AB 327 established Public Utilities Code (PUC) § 769, which requires each utility to submit DRP proposals by July 1, 2015. Specifically, Section 769 requires that these utility filings do the following:

1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution

[1] *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning* (DRP Ruling), R.14-08-013, dated February 6, 2015.

infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.

2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

On August 20, 2014, the Commission initiated Rulemaking (R.) 14-08-013 to "establish policies, procedures, and rules" to guide California investor-owned utilities" in developing their DRP proposals.[2] On February 6, 2015, the Commission issued an Assigned Commissioner's Ruling (DRP Ruling), which identifies the following supplemental goals for the DRP proposal:

1) To support California's policy of significantly reducing greenhouse gas (GHG) reduction targets.

2) To modernize the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs' networks.

3) To enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner.

4) To animate opportunities for DERs to realize benefits through the provision of grid services.[3]

As part of the DRP Ruling, the Commission set forth very detailed guidance (Final Guidance) for utilities to follow in their Section 769 DRP filings. This Final Guidance provides the framework for not

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[2] DRP Ruling, p. 1.
[3] DRP Ruling, pp. 2-3.

only compliance with Section 769 but also the supplemental goals established by the DRP Ruling. The Final Guidance identified nine content categories:

1) Integration Capacity and Locational Value Analysis
2) Demonstration and Deployment
3) Data Access
4) Tariffs and Contracts
5) Safety Considerations
6) Barriers to Deployment
7) DRP Coordination with Utility General Rate Cases
8) DRP Coordination with Utility and CEC Load Forecasting
9) Phasing of Next Steps[4]

III.

SUMMARY OF SCE'S DISTRIBUTION RESOURCES PLAN

In compliance with Section 769, the ACR, and the Final Guidance, SCE respectfully submits the attached DRP for Commission approval. SCE's DRP addresses the requirements of Section 769, the ACR, and the Final Guidance. SCE's DRP is intended to facilitate a path forward towards increased customer choices and provides a roadmap for the evolution of the grid to not only integrate cost-effective DERs, but also support broader state goals such as the reduction of GHG, the accommodation of two-way energy flows, the enhancement of customer choice of new technologies and service, and the animation of opportunities for DERs to realize benefits through the provision of grid services.

SCE's DRP is organized as follows:

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[4] Final Guidance, pp. 1-2.

1) Chapter 1 identifies the key policy and value drivers that shape SCE's DRP, and provides an executive summary of the DRP.

2) Chapter 2 outlines SCE's (1) Integration Capacity Analysis, (2) Optimal Location Benefit Analysis (*i.e.,* locational net benefits methodology), (3) three DERs growth scenarios posed by the Commission, and (4) five demonstration and deployment projects.

3) Chapter 3 provides SCE's data access proposal.

4) Chapter 4 provides an overview of existing tariffs that govern and/or incent DERs, and recommends ways to leverage services or incentives that could be implemented as part of SCE's DRP demonstration projects. This chapter also recommends a process to determine how locational considerations could be integrated into existing tariffs and interconnection policies.

5) Chapter 5 provides the description of safety considerations consistent with Requirement 5 of the Final Guidance.

6) Chapter 6 identifies three categories of barriers – barriers to integration and interconnection of DERs onto the distribution grid, barriers that limit the ability of DERs to provide benefits, and barriers related to distribution system operational and infrastructure capability to enable DERs. SCE also makes recommendations on how to overcome each of these barriers.

7) Chapter 7 identifies a set of foundational modernization investments and makes recommendations regarding coordinating such investments with SCE's GRC. To support the Commission's stated future phases of DRP implementation, SCE requests that the Commission permit the company to file a Tier 1 Advice Letter that would establish a memorandum account, the Distributed Energy Resources Memorandum Account (DERMA). The account will record the incremental revenue requirement and O&M expense associated with SCE's spending on: (i) grid modernization and grid reinforcement to facilitate DERs for the years 2015-2017 and (ii) utility investments that may be needed for three of the demonstration and deployment projects—Demonstration Projects C, D and E—as described in Chapter 2. Establishing the DERMA will allow SCE the opportunity to recover the revenue requirement associated with these new and unanticipated expenditures if they exceed levels authorized in SCE's test year 2015 GRC. This review would take place in SCE's test year 2018 GRC.

8) Chapter 8 sets forth recommendations intended to transform utility and CEC forecasting to provide better information for both the utilities and among the agencies (*e.g.,* CEC) with a view to greater DERs penetration. This chapter also discusses the future vision of the DRP and the central role the distribution planning process will play between the DRP and the GRC. SCE also proposes forming a Distribution Planning Review Group (DPRG) to promote transparency in SCE's distribution planning process. Finally, this chapter describes SCE's support for the Commission's proposed phased approach to DRP filings.

IV.

STATUTORY AND PROCEDURAL REQUIREMENTS

A. Statutory and Other Authority (Rule 2.1)

SCE's Application complies with the Commission's Rules of Practice and Procedure, Rules 1.5 through 1.11 and 1.13, which specify the procedures for, among other things, filing documents. In addition, this request complies with Rules 2.1 of the Commission's Rules of Practice and Procedure.

Rule 2.1 requires that all applications: (1) clearly and concisely state authority or relief sought; (2) cite the statutory or other authority under which that relief is sought; and (3) be verified by the applicant. Rule 2.1(a), 2.1(b) and 2.1(c) set forth further requirements that are addressed separately below.

The relief being sought is Commission approval of the DRP accompanying this Application, and permission to file a Tier 1 Advice Letter that would establish a memorandum account, the Distributed Energy Resources Memorandum Account.

The statutory and other authority for this request include, but are not limited to, AB 327, codified in California Public Utilities Code § 769, the *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769*, the *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning*, the California Public Utilities Code, the Commission's Rules of Practice and Procedure, and prior decisions, orders, and resolutions of this Commission.

B. Verification (Rules 2.1 and 1.11)

As required by Rules 2.1 and 1.11 of the Commission's Rules of Practice and Procedure, this application has been verified by an officer, Ronald Nichols, SCE's Senior Vice President of Regulatory Affairs.

C. Legal Name and Correspondence (Rules 2.1(a) and 2.1(b))

Pursuant to Rule 2.1(a) and 2.1(b)[5] of the Commission's Rules of Practice and Procedure, the full legal name of the applicant is Southern California Edison Company. SCE is a corporation organized and existing under the laws of the State of California, and is primarily engaged in the business of generating, purchasing, transmitting, distributing and selling electric energy for light, heat and power in portions of central and southern California as a public utility subject to the jurisdiction of the Commission. SCE's properties, substantially all of which are located within the State of California, primarily consist of hydroelectric and thermal electric generating plants, together with transmission and distribution lines and other property necessary in connection with its business.

SCE's principal place of business is 2244 Walnut Grove Avenue, Rosemead, California, and its post office address and telephone number are:

Southern California Edison Company
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1212

Communications in regard to this Application are to be addressed to:

Matthew Dwyer
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Rosemead, California 91770
Telephone: (626) 302-6521
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5 Rule 2.1(a) requires the application to state the exact legal name of the applicant and location of its principal place of business, and, if a corporation, the state under the laws of which the applicant was organized. Rule 2.1(b) requires the application to state the name, title, address, telephone number, facsimile transmission number, and e-mail address of the person to whom correspondence or communications in regard to the application are to be addressed.

To request a copy of this Application, please contact:

Case Administration
Southern California Edison Company
P. O. Box 800
2244 Walnut Grove Avenue
Rosemead, CA 91770
Telephone: (626) 302-1063
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E-mail: case.admin@sce.com

D. Proposed Categorization, Need for Hearings, Issues to Be Considered, Proposed Schedule (Rule 2.1(c))

Rule 2.1(c) requires that applications shall state "[t]he proposed category for the proceeding, the need for hearing, the issues to be considered, and a proposed schedule." These requirements are discussed below.

1) Proposed Categorization

SCE proposes to characterize this proceeding as "quasi-legislative" as defined in the Commission's Rules of Practice and Procedure, Rule 1.3(d) and Public Utilities Code § 1701.1(c)(1).

2) Issues to Be Considered

The issues to be considered in this Application concern the approval of SCE's proposed Distribution Resources Plan, which is attached to this Application, and permission to file a Tier 1 Advice Letter that would establish a memorandum account, the Distributed Energy Resources Memorandum Account.

3) Proposed Schedule and Hearings for Resolution of Issues

At this time, SCE does not believe hearings will be necessary. SCE recommends that the Commission use workshops as a mechanism for seeking public comment and input on the DRP submitted by SCE. Workshops offer an opportunity to engage in iterative discussions that accommodate the complicated and nuanced natured of DRP issues. SCE proposes the following schedule:

Application filed:	July 1, 2015
Responses/Protests due:	August 3, 2015
Reply to Responses/Protests:	August 17, 2015
Workshops	September – October 2015
Opening Briefs:	November 13, 2015
Reply Briefs due:	December 18, 2015
Proposed Decision:	February 10, 2016
Comments on Proposed Decision:	March 1, 2016
Replies to Comments:	March 7, 2016
Final Commission Decision:	March 2016

E. Organization and Qualification to Transact Business (Rule 2.2)

In compliance with Rule 2.2 of the Commission's Rules of Practice and Procedure, a copy of SCE's Certificate of Restated Articles of Incorporation, effective on March 2, 2006, and presently in effect, certified by the California Secretary of State, was filed with the Commission on March 14, 2006, in connection with Application No. 06-03-020, and is by reference made a part hereof.

A copy of SCE's Certificate of Determination of Preferences of the Series D Preference Stock filed with the California Secretary of State on March 7, 2011, and presently in effect, certified by the California Secretary of State, was filed with the Commission on April 1, 2011, in connection with Application No. 11-04-001, and is by reference made a part hereof.

A copy of SCE's Certificate of Determination of Preferences of the Series E Preference Stock filed with the California Secretary of State on January 12, 2012, and a copy of SCE's Certificate of Increase of Authorized Shares of the Series E Preference Stock filed with the California Secretary of State on January 31, 2012, and presently in effect, certified by the California Secretary of State, was filed with the Commission on March 5, 2012, in connection with Application No. 12-03-004, and is by reference made a part hereof.

A copy of SCE's Certificate of Determination of Preferences of the Series F Preference Stock filed with the California Secretary of State on May 5, 2012, and presently in effect, certified by the

California Secretary of State, was filed with the Commission on June 29, 2012, in connection with Application No. 12-06-017, and is by reference made a part hereof.

A copy of SCE's Certificate of Determination of Preferences of the Series G Preference Stock filed with the California Secretary of State on January 24, 2013, and presently in effect, certified by the California Secretary of State, was filed with the Commission on January 31, 2013, in connection with Application No. 13-01-016, and is by reference made a part hereof.

A copy of SCE's Certificate of Determination of Preferences of the Series H Preference Stock filed with the California Secretary of State on February 28, 2014, and presently in effect, certified by the California Secretary of State, was filed with the Commission on March 24, 2014, in connection with Application No. 14-03-013, and is by reference made a part hereof.

Certain classes and series of SCE's capital stock are listed on a "national securities exchange" as defined in the Securities Exchange Act of 1934 and copies of SCE's latest Annual Report to Shareholders and its latest proxy statement sent to its stockholders has been filed with the Commission with a letter of transmittal dated March 13, 2015, pursuant to General Order Nos. 65-A and 104-A of the Commission.

F. Service

SCE will serve this Application as required by the Public Utilities Code and the Commission's Rules of Practice and Procedure. In addition, pending the establishment of a new service list for this new proceeding, a copy of this Application, including attachments, is also being served as of this date to the service list for R.14-08-013.

V.

CONCLUSION

SCE respectfully requests that the Commission approve its Distribution Resources Plan and permit SCE to file a Tier 1 Advice Letter that would establish a memorandum account, the Distributed Energy Resources Memorandum Account.

Respectfully submitted,

/s/ Matthew Dwyer

By: Matthew Dwyer
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Dated: **July 1, 2015**

VERIFICATION

(See Rule 1.11)

Southern California Edison Company

I am an officer of the applicant corporation herein, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to the matters that are herein stated on information and belief, and as to those matters, I believe them to be true.

/s/ Ronald Owen Nichols

By: Ronald Owen Nichols
Senior Vice President of Regulatory Affairs
SOUTHERN CALIFORNIA EDISON COMPANY

Date: July 1, 2015

At Rosemead, California

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of Its Distribution Resources Plan	))))	Application No. 15-07-_____ (Filed July 1, 2015)

SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) NOTICE OF AVAILABILITY OF ITS DISTRIBUTION RESOURCES PLAN

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Dated: July 1, 2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of Its Distribution Resources Plan	))))	Application No. 15-07-_____ (Filed July 1, 2015)

SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) NOTICE OF AVAILABILITY OF ITS DISTRIBUTION RESOURCES PLAN

Pursuant to Rule 1.9 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Southern California Edison Company hereby provides this Notice of Availability of: Application of Southern California Edison Company (U 338-E) for Approval of Its Distribution Resources Plan, filed with the Commission and served via this e-mail to the official service lists on July 1, 2015, in the above-captioned docket.

To access the Application, Distribution Resources Plan, and Appendix from SCE's website, go to the following URL:

1. Go to www.sce.com/applications.
2. In the search box, enter "DRP" and hit "Go."
3. The Application, Distribution Resources Plan, and Appendices are presented in Adobe Acrobat (PDF) format and can be viewed online, printed, or saved to your hard drive.

Pursuant to Rule 2.3(c) of the Commission's Rules of Practice and Procedure, you may receive a copy of the Application by directing your request in writing to:

Mr. David Balandran, Case Administration
Law Department
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2244 Walnut Grove Avenue
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Dated at Rosemead, California, on this 1st day of July, 2015.

Respectfully submitted,

By: *<u>/s/ Matthew Dwyer</u>*

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Dated: **July 1, 2015**

Attachment

SCE Distribution Resources Plan

SOUTHERN CALIFORNIA
EDISON®
An *EDISON INTERNATIONAL®* Company

Distribution Resources Plan

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Chapter 1:
Distribution Resources Plan Introduction and Executive Summary

I.

CHAPTER 1: DISTRIBUTION RESOURCES PLAN INTRODUCTION AND EXECUTIVE SUMMARY

A. Introduction

1. The Electric Industry Is Undergoing a Transformation

The electric industry is undergoing transformative changes, which are largely centered on the distribution system. As distributed generation resources proliferate, power that used to flow in one-direction on the distribution system – from central power plants to customers – is now also flowing from end-use customers back to the distribution grid. At the same time, innovation in energy storage means that electricity no longer must be used immediately but can be stored and used when needed. Likewise, "electricity-as-fuel" resources such as electric vehicles are gaining greater market penetration and have the potential to become important components of the distribution system via vehicle-to-grid services and smart charging. These and many other distributed energy resources (DERs), such as demand response and energy efficiency, have the potential to offer customers more choices, more control over their energy bills, and cleaner power. In addition, when strategically located, distributed energy resources could potentially defer or substitute for conventional infrastructure such as large power plants, transmission lines, and distribution system infrastructure.

The existing distribution system is not structured to accommodate and facilitate these changes; it was designed for one-way flow of electricity from big central generation stations across high-voltage transmission lines to the distribution system and then to individual homes and businesses.[1] Given this one-way structure, SCE's distribution system

[1] SCE operates a very large electricity distribution system to serve approximately 14 million customers in about 430 cities and communities. It maintains over 90,000 miles of distribution lines and 720,000 distribution transformers.

operators have limited visualization tools and limited ability to control resources for monitoring and adjusting power flow on the distribution system.

The distribution grid of the future will look very different. To enhance customer choice for new technologies and services, as well as to manage bidirectional flows from many resources having a variety of generation and consumption patterns, the electric distribution system must become more dynamic, flexible, and resilient. Distribution planning must be greatly enhanced to recognize the value that distributed resources play in offsetting the need for transmission and distribution capital investment. With end-use customers playing a much more active role in generating and storing power, the distribution system is becoming a more complex two-way system that needs more sophisticated and advanced technologies and capabilities.

2. The Legislature and the Commission Recognize This Changing Paradigm

Recognizing this changing paradigm, the California Legislature adopted California Assembly Bill (AB) 327, codified as Public Utilities Code Section 769, which requires each utility to submit a Distribution Resources Plan (DRP) proposal by July 1, 2015. Specifically, Public Utilities Code (PUC) Section 769 requires these utility filings to:

1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.

2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

3) Propose cost-effective methods of effectively coordinating existing Commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

In response, on August 20, 2014, the California Public Utilities Commission (CPUC or Commission) initiated Rulemaking (R.) 14-08-013 (DRP OIR) to "establish policies, procedures and rules" to guide California utilities in developing their DRP proposals.[2] On February 6, 2015, the Commission issued an Assigned Commissioner's Ruling (DRP Ruling), which identifies the following supplemental goals for the DRP proposals:[3]

1) To support California's policy of significantly reducing greenhouse gas (GHG) reduction targets;

2) To modernize the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs' networks;

3) To enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner; and

4) To animate opportunities for DERs to realize benefits through the provision of grid services.

As part of the DRP Ruling, the Commission set forth detailed guidance (Final Guidance) for utilities to follow in their Section 769 compliance filings.[4] This Final Guidance provides the framework for compliance with Section 769 and the supplemental goals established by the DRP Ruling. Section 769 and the DRP Ruling are important first steps in planning for the transformative change of the electric distribution system. SCE supports the Commission's goals outlined in the DRP Ruling and its efforts to implement Section 769.

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[2] Ruling (R).14-08-013, *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769*, p. 1.

[3] R.14-08-013, *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning*, dated February 6, 2015.

[4] *See* Attachment to the DRP Ruling, entitled "Attachment: Guidance for Section 769 – Distribution Resource Planning."

3. The Grid of the Future Is an Important Tool in Achieving the State's Goals

An integrated bidirectional distribution system is key to implementing many of the strategic policy initiatives and technologies necessary to achieve the State's policy goals. Today's distribution grid structure reflects a basic economic principle that by pooling the diverse electricity needs of customers, all customers benefit. At a most basic level, a business using power during the day can be paired with a residential customer using power in the evening, so the overall peak demand on the system is reduced and generation resources can be shared and sized more efficiently. This aggregation of diverse loads lowers costs to customers and enables a more reliable, constant, and stable supply of electricity.

Until recently, these diverse customers have received power from relatively large, central station power sources. With energy and environmental policy changes, as well as the advancement of distributed generation technologies, that paradigm is changing. A very large number of much smaller renewable power sources have begun supplying power to the grid on an intermittent basis. As much as this diversification of generation is changing the electric power landscape, a basic principle of the electric grid remains the same: the grid is an indispensable and powerful tool for pooling diverse generation resources to maximize customer choices and benefits with a view to new service paradigms and opportunities for DERs. The 21st century distribution grid will continue to serve as the backbone of the electric system – enabling technological and financing innovations by bringing together customers and third party-owned devices, to maximize the opportunities for both to interact in new ways, while providing reliability and choices across the State.

4. To Achieve the Grid of the Future, SCE Must Transform Its Current Processes

While an integrated bidirectional distribution grid is central to achieving California's clean energy vision, it requires greater functionality than exists today. To achieve the grid of the future for customers, SCE plans to transform its current distribution planning and operating processes to make them more dynamic, to provide more operator visibility, and to recognize the full integration of DERs. As the DRP Ruling correctly recognizes, achievement of these goals will require "the need to add new infrastructure, enhance existing networks and adopt new analytical tools."[5] To accomplish this vision, SCE believes that investments are needed to modernize the distribution grid. These investments will require regulatory and contractual frameworks that encourage DER optimization, including functionality that allows a DER to provide both distribution system reliability support and wholesale market services. Achieving optimum system value of the changes contemplated in the DRP process will require coordination with, and likely changes to, market rules and protocols of the California Independent System Operator Corporation (CAISO).

SCE supports the Commission's objective of enabling the interconnection of DERs, integrating DERs into the distribution system in a more open and transparent way, and optimizing the use of DERs in a manner that benefits all customers. As reflected in this DRP, SCE proposes (1) to enhance the electric system's capability to add more DERs at the distribution level through: modernization of system planning, design, and operations; (2) increasing integration capacity where DER deployment may be beneficial; and (3) exchanging timely information to guide DER deployment in optimal locations. SCE also plans to make investments in infrastructure upgrades and advanced technologies that SCE believes will maximize the benefits of DERs for market and grid reliability functions. Such measures include deployment of digital monitoring and control devices, advanced communications networks, and automation in the distribution system. These investments, together with the tools and methodologies developed in this DRP, will also create opportunities for DERs to provide an alternative to the most costly distribution upgrades that might otherwise have been necessary to meet customer demand. In making integration

[5] DRP Ruling, p. 3.

capacity investments, SCE will focus on those locations where DERs can provide benefits to the grid, taking into account all associated costs, including the costs of capacity increases.

To this end, SCE is proposing investment and a cost recovery mechanism to expedite the transformation to this new grid. By making an early commitment to "no regrets" investments, California can enjoy the benefits of DER deployment earlier and consistent with the Commission's stated goals. These topics are covered in Chapter 7.

B. Guiding Principles

The DRP is intended to establish policies, tools, and methodologies to guide IOUs in developing their DRPs and to incorporate DERs into each IOU's distribution system planning, operations, and investment processes. SCE proposes the following guiding principles to assist the Commission, the IOUs, and stakeholders as they develop these policies, tools, and methodologies.

1. Promoting Customer Choice and Customer Engagement Are Key Objectives

As a guiding principle, the Commission, the IOUs, and stakeholders should strive to create a plug-and-play grid to enable customer choice and engagement related to DER technologies and services. The collective vision should be to create a power system into which customers can seamlessly connect their devices, be they electric vehicles, solar installations, energy storage devices, or other innovative and clean power technologies.

As SCE's customers, including businesses and households, become increasingly reliant on technology and increasingly knowledgeable and engaged in how their energy is sourced, delivered, and used, SCE's relationship with its customers grows ever more important. Customers expect from SCE a modernized and safe power system that offers them clean, reliable, and affordable power, while also offering them greater control over their energy usage. SCE must modernize the way it engages with customers to meet their evolving needs and preferences. This includes facilitating customer choice by supporting customized electricity services and by involving customers in how they consume and manage their electricity usage. Going forward, transparency and data access around distribution planning, interconnection, and operations will also become key to enabling customers to quickly and efficiently integrate DERs in to the grid. Likewise, data access will also allow the IOUs to monitor, predict, and control DERs so that their technical capabilities are fully utilized, while properly protecting customer data privacy and system reliability.

2. The Distribution Grid Can Play a Key Role in Reducing Carbon in California

Earlier this year, Governor Brown recognized the importance of the electricity sector in meeting California's ambitious GHG reduction goals by integrating "more distributed power, expanded rooftop solar, microgrids, an energy imbalance market, battery storage, the full integration of information technology and electrical distribution and millions of electric and low-carbon vehicles."[6] The distribution system provides a powerful platform for facilitating the growth of these solutions and achieving a low-carbon future. First, a bidirectional distribution system can be used to uniquely improve DER performance. Second, the distribution system enables all customers to benefit from the integration of a variety of low-carbon DERs. Finally, the electricity sector can help reduce GHG emissions in other sectors such as transportation. For example, a robust system of local distributed resources will complement the increased penetration of "electricity-as-fuel" technologies, such as plug-in electric vehicles and electric public transportation. This could drastically reduce emissions from the millions of vehicles on the road each day. Therefore, as a guiding principle, the distribution system should be a key component of the State's ambitious GHG reduction plans.

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6 Governor Brown's Inaugural Speech Transcript, *available at*: http://www.latimes.com/local/political/la-me-pc-brown-speech-text-20150105-story.html#page=3.

3. Safety, Reliability, and Resiliency Must Remain Paramount Objectives

The safe and reliable operation of the grid must remain of paramount importance in implementing the DRP. First and foremost, the electric grid must remain safe to customers, employees, and the public. Also, as customers continue to adopt increasingly higher levels of digital technology in all aspects of their lives, their tolerance for power outages decreases. Ensuring that the grid is robust, resilient, and has high power quality is critical. Likewise, the grid must be fortified to promote cybersecurity and mitigate the impacts of a cyberattack.

Given the importance of safety and reliability, a measured, tested, and fact-based approach to DER integration should be followed to ensure that grid operators and system planners understand and mitigate any adverse impacts of widespread DER integration. Demonstration projects, and, in particular projects that involve field-testing and learning-by-doing in a controlled environment, will provide utilities, third-parties and the Commission with greater insight into the potential safety and reliability issues related to high levels of DER penetration, the use of DERs to defer conventional infrastructure, and the development of islanded microgrids. Knowledge and insight gained from demonstration projects should inform future policy and planning decisions related to DER deployment.

4. Costs of Electric Service Must Remain Affordable and Equitably-Apportioned to Customers

The integrated grid is an important shared social asset that supports universal provision of electric service at reasonable prices, subject to public oversight and input. Even as the industry evolves to take maximum advantage of evolving technological advances in DERs, affordability of electric service to all customers remains an important priority.

As a guiding principle and in order to promote affordability and the equitable sharing of costs among all customers, the costs of maintaining and bolstering the grid and integrating DERs should be borne on a cost-causation basis, with common costs shared efficiently and equitably among all customers. The Commission has upheld the equitable principle of cost-causation.[7] This principle should apply with equal force to utility, direct access, and community choice aggregation customers.[8] Appropriate cost-sharing rules will be important in directing the efficient evolution of the grid. These rules will also ensure that, at a minimum, all customers have access to safe and reliable electric service, at a reasonable cost. Finally, such rules promote a sustainable transition to the widespread utilization of DERs for the benefit of all customers.

5. Competitive Processes Should Be Utilized to the Greatest Extent Possible

The Commission has long supported the notion of reliance on competitive processes, including for procurement of clean energy resources, to provide the greatest overall value to customers. In order to ensure a robust market for DERs, both as energy resources and as infrastructure alternatives, a regulatory framework that promotes competition is needed. In the case of DERs sourced by the utility, competitive processes that promote selection of the highest value DERs should be preferred; the market should dictate the technology solutions that provide the greatest value to all customers and drive innovation.

C. Executive Summary of DRP

This section summarizes SCE's DRP proposals, which are discussed in greater detail in Chapters 2 through 8. SCE's DRP proposals comply with the requirements of Public Utilities Code Section 769 and the Final Guidance[9] and SCE proposes a constructive path forward to facilitating the Commission's and State's goal of DER development.

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7 The Commission has defined cost causation to mean that "costs should be borne by those customers who cause the utility to incur the expense." R.12-06-013, p. 13. In the first Commission decision implementing PUC Section 769, Decision (D).14-06-029, Commissioner Florio and his colleagues unanimously agreed that "[w]ith its passage, the utilities can now propose residential rates that are more reflective of cost, in keeping with the Commission's principle that rates should be based on cost-causation." *Decision* (D.) 14-06-029, p. 5.

8 *See Decision* D.08-09-012, pp. 9-10.

9 *See* Appendix B for a table that identifies each Final Guidance and AB 327 Compliance Requirement and where that Requirement is addressed in the DRP.

1. Chapter 2: Integration Capacity Analysis; Locational Value Analysis; DER Growth Scenarios; and Demonstration and Deployment Projects (Final Guidance Requirements 1 and 2)

This chapter outlines SCE's: (1) Integration Capacity Analysis (ICA), (2) locational net benefits methodology (LNBM), (3) the three DER growth scenarios posed by the Commission, and (4) demonstration and deployment projects. As envisioned by SCE, the ICA, LNBM, DER scenarios, and demonstration and deployment projects should shape a development path that, when coupled with the requisite software and grid technology designed to accommodate high DER penetration and maximize DER functionality, will move the State towards the constructive penetration of DERs envisioned by the Governor and the Commission.

a) Integration Capacity Analysis

SCE's ICA identifies the hosting (or integration) capacity of distribution circuits (or feeders) and is intended to facilitate integration of DERs on SCE's distribution system by (1) enabling more efficient siting of DERs in areas of the distribution system that have capacity, (2) informing SCE's distribution planning processes, and (3) providing a foundation for improvements to rules that govern the interconnection of DERs onto SCE's distribution system.

To create the ICA, SCE developed a methodology that quantifies the capability of the system to integrate DERs within thermal ratings, protection system limits, and power quality and safety standards of existing equipment.[10] SCE used power system modeling software to implement the ICA methodology and performed a rigorous evaluation on 30 representative

[10] The methodology for each IOU relies on common limitation categories (e.g., thermal overloads, voltage impacts, protection coordination), but there may be some variation in each IOU's respective ICA parameters due to operational differences—including design criteria—or available data. Further, each IOU used load flow modelling that relied upon a power flow modelling tool that evaluated multiple scenarios.

circuits, down to the line segment level. SCE then extrapolated the results of the ICA performed on the representative circuits to the remaining 4,636 distribution circuits. This approach permits SCE to provide an estimate of the potential DER hosting capacity for each of its distribution circuits at the line segment level.

To assist developers and customers in locating the areas where there may be sufficient existing hosting capacity for DER projects, SCE will publish the results of its ICA via a new online tool, the Distributed Energy Resource Interconnection Maps (DERiM). These maps will be publicly available beginning July 1, 2015. The ICA, as reflected in the DERiM, will be updated monthly.

Within this chapter, SCE conducts an assessment of the current deployment of DER territory-wide, and provides information on distribution circuits with high levels of DER penetration. SCE also provides an assessment of the impacts of near term load growth and planned investments within a two-year period on the ICA.

Finally, SCE considered how the ICA could create improvements or efficiencies for the interconnection of distributed generation. SCE believes the ICA and its associated DERiM tool will provide significant assistance for interconnection customers by providing detailed information regarding the capacity on a distribution circuit line segment.

b) Locational Net Benefits Methodology

SCE's proposed LNBM framework is designed to prioritize locations where DERs may be able to provide net benefits. Consistent with the other IOUs, SCE relied upon E3's Distributed Energy Resource Avoided Cost (DERAC) tool, which feeds into the CPUC-approved E3 DR/EE/NEM cost-effectiveness calculator, as the starting point to identify the benefits that SCE should take into account in developing its LNBM. The DERAC calculates the value of benefit components at a system level based upon a collection of benefits and costs. SCE has proposed methods to replace the DERAC's system-level calculations with location-specific values of these benefit components. SCE has also added value components to the elements required to be considered by the Final Guidance in addition to those reflected in E3's calculators. SCE also proposes forming a Distribution Planning Review Group (DPRG), modeled off of the utilities' Procurement Review Groups, to promote transparency in SCE's distribution planning process.

c) DER Growth Scenarios

In Chapter 2, SCE also presents three 10-year DER growth scenarios that project potential growth of DERs through 2025 at a system level: Scenario 1 adapted the IEPR "Trajectory" case; Scenario 2 adapted the IEPR "High Growth" case; and Scenario 3 developed a very high potential growth case, which included assumptions based on various State goals. These scenarios were allocated to the distribution circuit level based on an assessment of the types of customers on the circuit who have the greatest economical potential or interest in installing various types of DERs. Then, SCE performed an assessment that identified the impacts of increased penetration on distribution planning in the following three areas: (1) the impact on distribution system load growth; (2) impact on distribution facilities; and (3) the impact on the planning process and the need for new planning capabilities.

d) Deployment and Demonstration Projects

Consistent with the Final Guidance, SCE is proposing five demonstration and deployment projects, described in Chapter 2. Two projects – one demonstrating dynamic ICA and the second demonstrating the optimal location benefit analysis methodology – are simulations and studies. The other three projects – one demonstrating DER locational benefits, a second demonstrating distribution operations at high penetrations of DERs, and a third demonstrating DER dispatch to meet reliability needs – are field demonstrations. These five projects will assist SCE and the Commission in evaluating the new tools and methodologies proposed in this DRP, help overcome barriers related to DER integration, and advance DER penetration.

2. Chapter 3: Data Access (Final Guidance Requirement 3)

As a greater number of DERs are interconnected to the grid and as telecommunications technologies advance, an increasingly greater volume of data will become available to the utilities, the Commission, and third parties. This data can be valuable in supporting real-time grid operations, forecasting and planning for the future grid, and encouraging the growth and development of DERs. SCE is making a significant amount of useful data available immediately through the use of DERiM maps. Moreover, SCE looks forward to working with stakeholders to determine other ways to compile and share data that is useful to third parties, while protecting customer rights and interests.

3. Chapter 4: Tariffs and Contracts (Final Guidance Requirement 4)

This chapter provides an outline of existing tariffs that govern and/or incent DERs. SCE also recommends ways to leverage services or incentives that could be implemented as part of SCE's DRP demonstration projects, including enhancing its current customer program incentives to encourage DER deployment in specific locations. This chapter also recommends a process to determine how locational considerations could be integrated into existing tariffs and interconnection policies.

4. Chapter 5: Safety Considerations (Final Guidance Requirement 5)

In Chapter 5, SCE catalogues the current safety and reliability standards related to DERs and describes the potential of DERs to provide added grid reliability and resiliency, and improve overall grid safety. Large numbers of DERs connected to the grid in one location can create safety concerns. Likewise, certain DER equipment, such as energy storage and PV systems, present particular safety concerns for grid equipment, utility workers, and/or the general public. Safety concerns can be mitigated or obviated by grid modernization, technical changes, and enhanced standards and outreach to government officials. Through these efforts, DERs and the grid can be made safer for the customer, the public, and utility workers.

5. Chapter 6: Overcoming Barriers to Deployment of DERs (Final Guidance Requirement 6)

To achieve a 21st century power system, both the electrical power system and the DERs will need to change rapidly to overcome many barriers. In Chapter 6, SCE identifies three categories of barriers – barriers to integration and interconnection, barriers that limit the ability of DERs to provide benefits, and barriers related to distribution system operational and infrastructure capability to enable DERs. SCE also makes recommendations on how grid modernization can overcome these barriers.

6. Chapter 7: SCE's Grid Modernization Investments (Final Guidance Requirement 7)

As part of that DRP Ruling, the Commission directed SCE to include, within its DRP proposal, a "platform for future investments in energy delivery infrastructure, primarily but not limited to the electric distribution networks owned and operated by IOUs."[11] Specifically, the Final Guidance directs the utilities to "describe what specific actions or investments may be included in their next GRCs as a result of the DRP process."[12]

SCE has identified a set of foundational modernization investments that it believes will benefit customers and enable the increased penetration of DERs. These investments will provide SCE access to an increased amount of system data and will enhance the analytical capabilities of SCE planners and operators – ultimately resulting in improved safety and reliability for customers while minimizing overall distribution system cost and maximizing customer benefits from investments in distributed resources. These investments will also enhance the ability of DERs to meet customer reliability needs. Associated with this ability is the potential for DERs to defer or avoid future projects, driven

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11 DRP Ruling, p. 3.

12 Final Guidance, p. 11.

by load growth, if the DER portfolios can provide similar levels of safety and reliability at lower costs.

Due to SCE's large system, it will take years to complete these grid modernization efforts and fully integrate a new set of tools, technologies, and processes. Investments in such infrastructure should begin immediately to enable SCE to meet the Commission's stated future phases of DRP implementation, including the accommodation of two-way flows of electricity, the evaluation of the capacity of the distribution system, the evaluation of DERs as alternative providers of reliability functions, and the potential for development of microgrids.

SCE's 2015 GRC was filed in July 2013 and does not include the types and amount of grid reinforcement and grid modernization expenditures needed to facilitate these goals. The Commission has also not yet issued a Proposed Decision in SCE's 2015 GRC, nor adopted a final decision, so there is uncertainty regarding how much funding SCE will have available. SCE requests that the Commission permit SCE to file a Tier 1 Advice Letter that would establish a memorandum account, the Distributed Energy Resources Memorandum Account (DERMA). SCE is proposing to record in the DERMA the incremental capital revenue requirement and operations and maintenance (O&M) expense associated with its spending on: (i) accelerated foundational grid modernization to facilitate DERs during years 2015-2017 and (ii) utility investments to support the field demonstration and deployment projects—as described in Chapter 2. Establishing the DERMA will allow SCE the opportunity to recover the balance recorded in the DERMA upon a review of these capital expenditures and O&M expenses if they exceed levels authorized in SCE's test year 2015 GRC. This review would take place in SCE's test year 2018 GRC.

7. Chapter 8: DRP Coordination on Load Forecasting, GRC, and Other Proceedings; Phasing of Next Steps (Final Guidance Requirements 8 and 9)

In Chapter 8, SCE recommends transforming utility and CEC forecasting to provide better information for total system planning, including the distribution system. This includes investment in tools that will support enhanced accuracy and granularity in forecasting DERs and a proposal for a higher level of coordination among the agencies (CEC, CAISO, and CPUC) to improve distribution system planning.

SCE envisions that the policies, tools, and methodologies developed in the DRP will inform SCE's GRC request. Specifically, SCE envisions using the DRP process to establish DER policies, tools, and methodologies, such as the LNBM. These tools will inform SCE's internal annual planning process, which will, in turn, determine the actions and investments that SCE will pursue in its GRC. The output of that planning process will also be used to consider DERs as an alternative to infrastructure investments. SCE recommends coordination among the DRP and several other relevant proceedings and addresses phasing of next steps. SCE also proposes forming a Distribution Planning Review Group (DPRG) to promote transparency related to certain aspects of SCE's distribution planning activities related to DER deployment. Over time, SCE anticipates that the DRP would no longer need to be a biennial proceeding but could precede each utility's GRC.

Chapter 2:

Integration Capacity Analysis, Optimal Location Benefit Analysis, DER Growth Scenarios, and Demonstration and Deployment

II.

CHAPTER 2: INTEGRATION CAPACITY ANALYSIS, OPTIMAL LOCATION BENEFIT ANALYSIS, DER GROWTH SCENARIOS, AND DEMONSTRATION AND DEPLOYMENT

A. Introduction and Executive Summary

SCE's DRP is intended "to begin the process of moving the IOUs towards a more robust integration of DERs into their distribution system planning, operations, and investment."[13] The planning methodologies (the integration capacity analysis and the locational net benefits methodology), the growth scenarios, and the proposed demonstration projects that are presented in this chapter represent a crucial first step in meeting the State's policy goals and advancing grid modernization efforts that will allow California to fully realize the benefits of DERs. The development of an analysis to determine available hosting (*i.e.,* integration) capacity may help to streamline interconnection processes, and the methodology to calculate locational net benefits will allow for identifying optimal locations where DERs can be deployed. These net benefits are based on an assessment of both costs and benefits. The development of three growth scenarios for DERs will support identification of potential future impacts and additional planning needs to allow for heightened penetration. The proposed demonstration projects seek to validate the methodologies developed within the DRP and to show how a modern grid can better enable DERs while meeting the power needs of all customers safely and reliably. Integrating the methodologies into the utility planning process and enhancing DER forecasting will help minimize overall system costs and maximize customer benefits from investments in DERs.

The Final Guidance directs utilities to develop three analytical frameworks related to DERs: (1) an integration capacity analysis (ICA); (2) a locational net benefits methodology (LNBM); and (3) DER growth scenarios (Final Guidance Requirement No. 1). The Final Guidance also directs utilities to "demonstrate the capabilities of DERs to meet grid planning and operational objectives" by

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13 DRP OIR, p. 4.

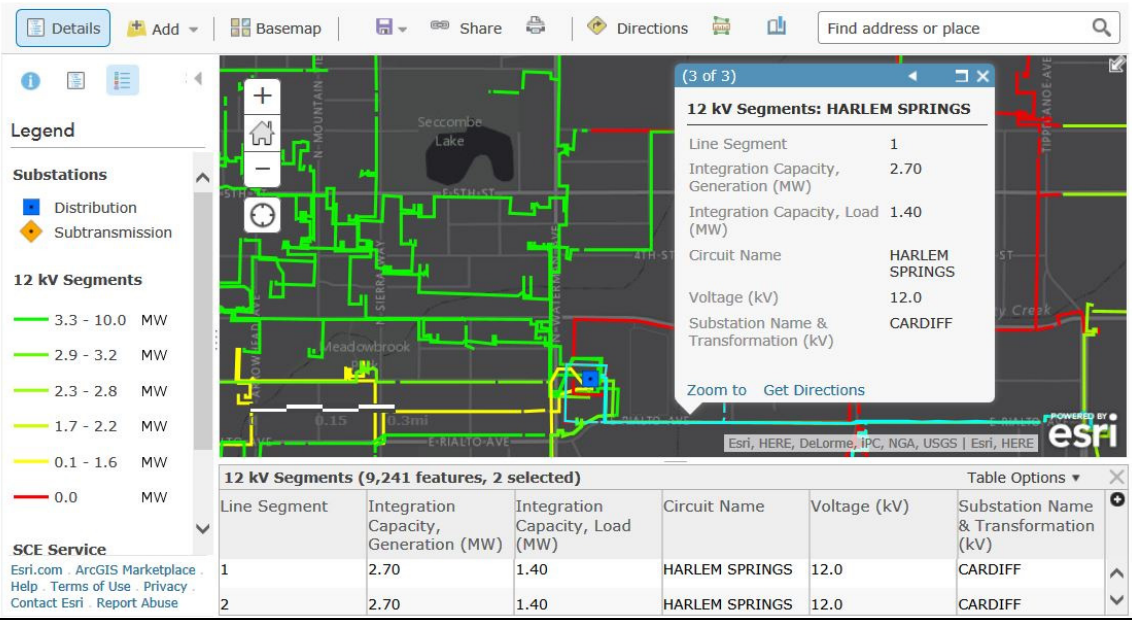
proposing DER-focused demonstration and deployment projects (Final Guidance Requirement No. 2). To meet these requirements, SCE has divided the remainder of Chapter 2 into four sections:

- Section B describes the ICA, which specifies how much DER hosting capacity is available on the distribution system (Final Guidance Requirement No. 1.a).
- Section C describes a LNBM, which is a unified methodology across all three IOUs (Final Guidance Requirement No. 1.b).
- Section D describes three 10-year scenarios that project various potential growth paths of DERs through 2025 (Final Guidance Requirement No. 1.c).
- Section E presents specifications for five demonstration projects (Final Guidance Requirement No. 2).

In Section B, SCE presents the results of its analysis of the distribution grid to integrate DERs using a set of representative circuits (or feeders) down to the distribution circuit segment level. SCE developed an online tool known as the Distributed Energy Resource Interconnection Maps (DERiM)[14] to provide ICA results intended to help customers, developers, and aggregators identify areas of interconnection where DERs will not likely need distribution upgrades. An example of a distribution circuit in the DERiM is shown within Figure II-1 below.

[14] *See* https://www.sce.com/wps/portal/home/business/generating-your-own-power/Grid-Interconnections/!ut/p/b0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOK9PF0cDd1NjDz9TUONDRzNnDyCfYLCjEz8DPWDU_P0C7IdFQE9YjA1/.

Figure II-1
DERiM Sample Map for a Distribution Circuit[15]



Based on the ICA results of the 30 representative circuits,[16] SCE identified overarching themes regarding how hosting capacity changes across the distribution system. The hosting capacity is heavily influenced by the nominal voltage of the distribution circuit, distance from source substation, type of cable and conductor, loading of the circuit, voltage regulating equipment (*e.g.*, voltage regulators, under-load tap changers), equipment ratings, and settings of protective devices. For example, the hosting capacity varies across the different voltage levels, resulting in higher hosting capacities at higher voltages, such as the 16kV and 33kV distribution feeders. Another factor influencing the hosting capacity of a distribution circuit is the electrical resistance between the location being analyzed and its source substation. The hosting capacity along a distribution circuit decreases as the electrical distance from the substation increases. This relationship results

15 Map or features illustrated within map are subject to change prior to the release of DERiM on July 1, 2015. Values included are for strictly for demonstration purposes and may include current hosting capacity values.

16 Appendix C lists the 30 representative circuits.

in higher hosting capacities closer to the source substation. Other factors influencing hosting capacity such as circuit loading are discussed in more detail in Section B.5.

Section B also describes the methodologies for determining ICA and selecting the representative circuits. A proposal to update ICA and conduct dynamic analysis on the remainder of circuits is also included. The section also describes opportunities for streamlining Rule 21[17] and using ICA to support EV installations.

Section C sets forth SCE's LNBM proposal. The LNBM is intended to quantify the net benefits that DERs can provide at specific locations, based on costs that may be avoided by deploying DERs. SCE relied upon Energy and Environmental Economics, Inc. (E3)'s[18] Distributed Energy Resource Avoided Cost (DERAC) calculator[19] as the starting point to identify the benefits that SCE should take into account in developing its LNBM. The DERAC calculates the value of benefit components at a system level based upon potential avoided costs. SCE has proposed methods to replace the DERAC's system-level calculations with location-specific values of these benefit components. SCE has also added value components that the Final Guidance required to be considered in addition to those reflected in E3's calculators. Figure II-2 below describes current DERAC components and how these components may be modified. For example, system loss factors in the current DERAC calculator can be replaced with location-specific loss factors in the LNBM. It should be noted that while some of the components may result in net benefits, others may result in net costs. Finally, based on the underlying technology and operating characteristics, certain DERs may provide only some of the benefits identified in the LNBM.

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17 SCE's recommended actions can be pursued in the Rule 21 rulemaking (R.11-09-011).

18 E3 refers to the consulting firm Energy and Environmental Economics, Inc. Further details can be found at https://www.ethree.com/.

19 Information about E3's DERAC calculator is available at https://ethree.com/public_projects/cpuc5.php.

Figure II-2
DRP Final Guidance Components Either Replace or Are Added to Avoided Cost Components in the Current DERAC Calculator[20]

Component	DERAC*	LNBM*
Generation Energy	• Forward market prices and the $/kWh fixed and variable operating costs of a CCGT	**DERAC Component Replaced With:** • Locational Marginal Prices (LMP) calculated at CAISO PNode or APnode to represent location specific avoided energy cost value
Losses	• System loss factors	**DERAC Component Replaced With:** • Location-specific loss factors
Generation Capacity	• Residual capacity value of a new simple-cycle combustion turbine	**DERAC Component Replaced With:** • Near term = Avoided Resource Adequacy (RA) procurement, including local RA and flexible RA • Long term = cost of new entry
Ancillary Services	• Percentage of generation energy value	**DERAC Component Replaced With:** • Difference between the energy-only value of the resource and the co-optimized energy + AS value of the resource
Transmission and Distribution (T&D) Capacity	• Marginal T&D costs from utility ratemaking filings	**DERAC Component Replaced With:** • Avoided transmission capital and operating expenditures • Avoided sub-transmission, substation and feeder capital and operating expenditures • Avoided distribution voltage capital and operating expenditures • Avoided distribution reliability capital and operating expenditures
Environment	• Synapse mid-level carbon forecast developed for use in electricity sector	**DERAC Component Removed:** • In SCE's method, this component is embedded within the LMP calculations for Generation Energy
Avoided RPS	• Renewable premium multiplied by reduction in RPS requirement	**DERAC Component Replaced With:** • DERAC method but with SCE values
Additional Components for LNBM		**Added To DERAC:** • Avoided renewables integration costs (quantitative; system-level) • Societal avoided costs (qualitative) • Avoided public safety costs (qualitative)

In Section D, SCE presents three DER growth scenarios. The first two scenarios adapted the Integrated Energy Policy Report (IEPR) "Trajectory" case and the IEPR "High Growth" case, respectively. The third scenario was developed based on very high potential DER growth that included assumptions of achieving various state energy and transportation goals. These scenarios were allocated to the distribution circuit level based on an assessment of the types of customers on the circuit who have the greatest economical potential or historic interest in installation of the various types of DERs. Then, SCE performed an assessment that identified the impacts of increased penetration on distribution planning in the following three areas: (1) the impact on

20 The components for DERAC and LNBM form the basis of an annual forecast; note that hourly forecast shapes may be needed.

distribution system load growth; (2) the impact on distribution facilities; and (3) the impact on the planning process and the need for new planning capabilities.

In Section E, SCE presents specifications for five demonstration projects. Two projects – demonstrating dynamic ICA and optimal location benefit analysis methodology – are simulations and studies. The other three projects – demonstrating DER locational benefits, distribution operations at high penetrations of DERs, and DER dispatch to meet reliability needs – are field demonstrations.

B. Integration Capacity Analysis

1. Overview of Integration Capacity Analysis

The development of an Integration Capacity Analysis (ICA) methodology is an important initial step to support reaching the goal of identifying the hosting (or integration) capacity of all the distribution circuits within the SCE service territory. This section describes the development of an ICA methodology and a new online tool, the DERiM, which will provide a forum for viewing the results of the ICA. While SCE used representative circuits to develop the ICA, this section also sets forth a plan to complete the ICA for all 4,636 circuits prior to the next DRP.

This section also assesses the current deployment of DERs within SCE's territory and provides findings from the ICA. In addition, to support timely communication of available hosting capacity that reflects current conditions, SCE has offered a proposal to update the results of the ICA on a periodic basis. Lastly, this section discusses the ICA's potential to support Rule 21 for distributed generation, and Rule 15 and 16 assessments of EV grid load impacts.

The Final Guidance requires SCE to develop an ICA that "will specify how much DER hosting capacity may be available on the distribution network."[21] The Final Guidance directs utilities to perform an ICA down to the line section level to identify the available DER hosting capacity on the distribution system. SCE addresses these requirements and other related requirements in the following sections:

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[21] DRP Ruling, p. 3.

- Section 2 assesses the current state of DER deployment at the SCE territory-level and DER projections under the three Growth Scenarios (Final Guidance Requirement No. 1.a.iv).
- Section 3 describes the common methodology for ICA and the software used to complete the analysis (Final Guidance Requirement No. 1.a.i and No. 1.a.iii).
- Section 4 summarizes the methodology for the selection of 30 representative circuits and extrapolation out to the remainder of the circuits (Final Guidance Requirement No. 1.a.v).
- Section 5 provides the findings of the ICA and describes the hosting capacity related to DERs that discharge energy and the hosting capacity related to DERs that consume energy (Final Guidance Requirement No. 1.a). Detailed ICA worksheets are provided in Appendix I.
- Section 6 assesses the impact of growth forecasts and planned investment on the hosting capacity within a two-year period (Final Guidance Requirement No. 1.a.ii).
- Section 7 highlights the new Distributed Energy Resources Interconnection Maps (DERiM) -- online maps which show the results of the Integration Capacity Analysis (Final Guidance Requirement No. 1.a.i).
- Section 8 proposes a process for providing updates to the Integration Capacity Analysis to reflect current conditions, and describes a plan for developing the capabilities to complete a dynamic ICA on SCE's 4,636 circuits (Final Guidance Requirement No. 1.a.vi).
- Section 9 discusses the use of ICA to support EV grid load impacts and an opportunity for streamlining Rule 21 for Distributed Generation (DG) due to ICA (Final Guidance Requirement No. 1.a.vii).

2. Assessment of the Current State of DER Deployment and DER Projections

Pursuant to the Final Guidance, this section assesses (1) the "current levels of DER deployment territory wide" for each DER category and (2) the "geographic dispersion with circuits that exhibit high levels of penetration."[22]

a) A View of Current DER Deployment

Table II-1 summarizes current levels of deployment territory-wide for each category of DERs for the SCE territory.

22 Final Guidance, p. 3.

Table II-1
Current Levels of DER Deployment Territory-Wide

DER Category	Installed Capacity/Demand Reduction (MW)
Distributed Renewable Generation	1,998 MW[23]
Energy Storage	7 MW[24]
Electric Vehicles	57 MW[25]
Energy Efficiency	1,122 MW[26]
Demand Response	1,177 MW[27]

The information found on Table II-1 shows each DER category and the installed capacity or demand reduction realized throughout the SCE territory. The table above only includes in-service projects, and does not include queued projects. In addition, SCE expects an increase in the number of DER installations in the future. For example, SCE's Energy Efficiency, California Solar

[23] Distributed Renewable Generation Installed Demand (MW) includes: (1) Cumulative NEM Installed Capacity as of May 2015, including cumulative installations approved for NEM interconnection since NEM inception in 1996 (does not include systems that terminated NEM interconnection with the utility); (2) Utility-owned generation as part of the Solar Photovoltaic Program (SPVP); (3) Distributed Renewable Generator projects interconnected to SCE's Distribution System for which a Power Purchase Agreement (PPA) has been executed, including Independent Power Producer (IPP) SPVP projects; (4) Projects interconnected to SCE's Distribution System pursuant to SCE's WDAT and Rule 21 as published on the Wholesale Distribution Access Tariff (WDAT) and Rule 21 – Interconnection Queue report on June 3, 2015: https://www.sce.com/nrc/aboutsce/regulatory/openaccess/wdat/wdat_queue.xls.

[24] Energy Storage Installed Demand (MW) includes: 1. Installed behind-the-meter Advanced Energy Storage from SCE's Self-Generation Incentive Program as of May 2015, 2. Projects interconnected to SCE's Distribution System pursuant to SCE's WDAT and Rule 21 as published on the Wholesale Distribution and Access Tariff (WDAT) and Rule 21 – Interconnection Queue report on June 3, 2015: https://www.sce.com/nrc/aboutsce/regulatory/openaccess/wdat/wdat_queue.xls.

[25] As customers are not required to report their acquisition of an Electric Vehicle, SCE is only able to report on the customers that have either volunteered the information or signed up to a TOU rate. It is estimated, based on POLK DMV registrations, that SCE only has visibility of about 38% of the vehicles in the SCE Service Territory. The value in this table only accounts for the Electric Vehicles for which SCE has information as of May 21, 2015.

[26] Energy Efficiency Installed Demand (MW) represents 2010 – 2014 Energy Efficiency program performance as reported in SCE EE Annual Reports, linked below. Demand value accounts for CFL Carryover, Codes & Standards, Energy Savings Assistance program, and Lighting Disposition: http://eestats.cpuc.ca.gov/Views/Documents.aspx.

[27] Demand Response figure is based on the most recent Load Impacts Study published on May 15, 2015.

Initiative, and Self-Generation Incentive Programs have funding commitments for future DER installations in the near-term. Similarly, SCE expects additional DER resources to be procured once contracts receive approval through the Local Capacity Requirements Request for Offers (LCR RFO), Energy Storage RFO, and other DER procurement frameworks.

Section D of this chapter illustrates SCE's DER deployment projections[28] under the Growth Scenarios required by the Final Guidance. For more granular information, down to the circuit level, please see SCE's DER Growth Worksheets.[29]

b) SCE Circuits with High Levels of Penetration

The Final Guidance requires "an assessment of geographic dispersion" of circuits that have a high level of DER penetration.[30] While the online DERiM maps will demonstrate the available capacity on distribution circuits, this section will provide information specifically regarding circuits that, as of May 5, 2015, have the highest level of Distributed Generation (DG)[31] penetration throughout SCE's distribution system. Total DG was provided (versus only renewable DG) because it considers all local generation connected to the distribution system. This information provides a better understanding of levels of penetration on a distribution circuit.

The Final Guidance did not define what constitutes a distribution circuit with a "high level" of DG penetration. SCE has assumed that the highest 1% of distribution circuits containing interconnected DG as circuits with "high levels" of penetration. Information on the amount of DG connected to each of these circuits can be found within Appendix E. To help visualize the geographical location of the distribution circuits with high levels of penetration within the SCE service territory, SCE aggregated the amount of interconnected DG of the top 1% of circuits up to

[28] The projected DER deployment is useful for the purposes identified by the final guidance and are not actual forecasts of DER penetration.

[29] Appendix J: DER Growth Scenarios Worksheets.

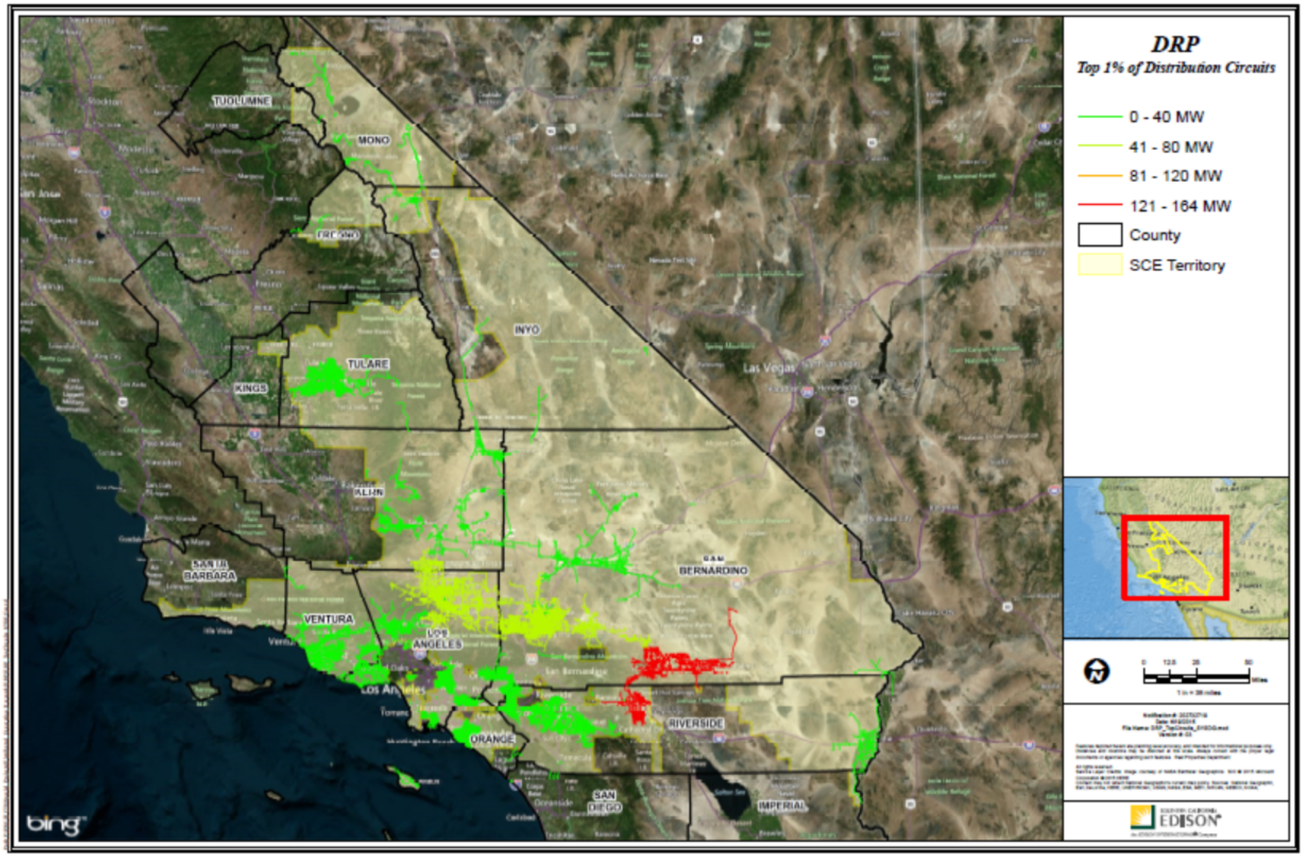
[30] Final Guidance, p. 3.

[31] Distributed Generation (DG) is considered to be any source of active electric power generation interconnected to any point on the distribution system. It is not limited to just DERs; it also encompasses non-renewable powered generation technology, such as diesel powered turbines.

the subtransmission system[32] level and mapped the results. As shown in the figure below, the areas with the lowest levels of penetration are green and those areas with the highest levels of penetration are red.

32 The subtransmission system is the portion of the SCE system that provides power to multiple distribution substations.

Figure II-3
Subtransmission Level View of Top 1% of Distribution Circuits with the Highest Level of DG Penetration[33]



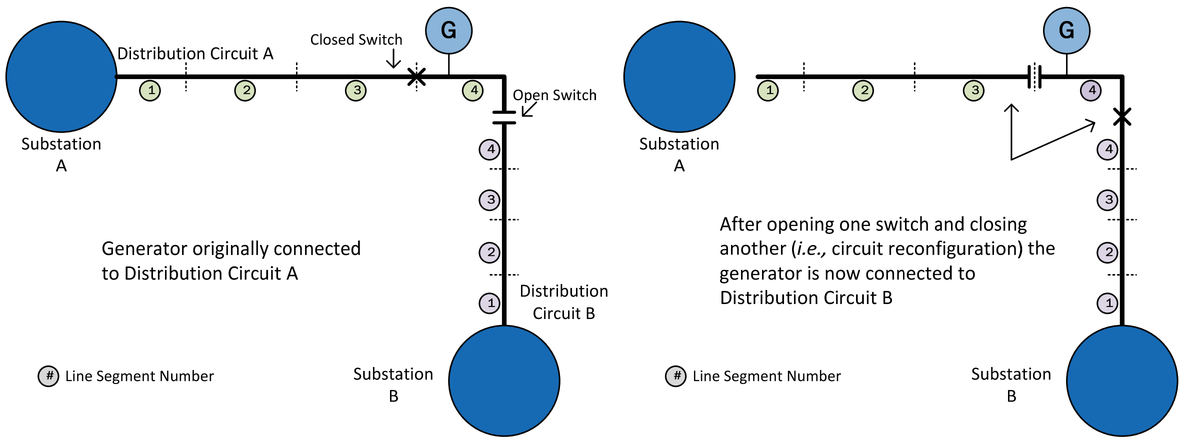
33 Text box in bottom right of image states: "Features depicted herein are planning level accuracy, and intended for informational purposes only. Distances and locations may be distorted at this scale. Always consult the proper legal documents or agencies regarding such features. Real properties Document. All rights reserved. Service Layer Credits: Image courtesy of NASA Earthstar Geographics SIO © 2015 Microsoft Corporation © 2015 HERE. Content may not reflect National Geographic's current map policy. Source: National Geographic, Esri, DeLome, HERE, UNEP-WCMC, USGS, NASA, ESA, METI, NRCAN, GEBCO, NOAA, increment P corp."

As seen on Figure II-3, the top 1% of distribution circuits with high levels of DG are aggregated in San Bernardino and Riverside counties, as well as north Los Angeles County. The amount of DG interconnected to these distribution circuits ranges from approximately 8 MW to 34 MW. The DG is interconnected across various voltage levels including 12 kV, 16 kV, and 33 kV. The larger DG resources (*i.e.,* those greater than approximately 13 MW) typically are interconnected to 33 kV distribution circuits. This information is meant to provide an understanding of the distribution circuits with the highest interconnected amounts of DG, and not to provide an indication of optimal levels of hosting capacity. For instance, these circuits may have distribution upgrades in place that allow them to accommodate higher levels of penetration. Information regarding the distribution circuits with high levels of interconnected DG can be found within Appendix E. The interconnected DG data is also available at the distribution circuit level on the RAM maps that will be available as part of the DERiM tool.[34]

It is important to note that due to the dynamic nature of the distribution system (*e.g.,* ongoing and future circuit reconfigurations), the list of circuits with high levels of DG may change in the future. Examples of distribution circuit reconfigurations include permanent transfers between multiple distribution circuits to mitigate criteria violations, accommodation of planned grid investments, and interconnection of load and DER projects. In the scenario shown on Figure II-4, a generator on one distribution circuit can be permanently transferred to another distribution circuit through the operation of field devices, such as switches. Distribution circuit reconfigurations such as the one depicted on Figure II-4 are very common and can be very complex with multiple distribution circuits involved. Overall, circuit reconfigurations are vital to the integrity of the distribution system as they help support the safe and reliable operation of the distribution system.

[34] The RAM Maps define "connected distributed generation" as "allocated generation," https://www.sce.com/wps/portal/home/regulatory/open-access-information/!ut/p/b0/04_Sj9CPykssy0xPLMnMz0vMAfGjz0lNLdwdPTyDDTwtfAKNDTydnDz9zdxMjA28jfQLsh0VAY010s4!/.

Figure II-4
Reconfiguration of Two Distribution Circuits Through the Operation of Two Field Switches



3. The Common Methodology Used Among All Utilities for the Integration Capacity Analysis

Per the Final Guidance, SCE developed a common methodology with the other IOUs that quantifies the capability of the system to integrate DERs within thermal ratings, protection system limits, and power quality and safety standards of existing equipment.[35] SCE's distribution system is designed and planned to maintain loading levels under equipment ratings and planned loading limits, as well as maintaining adequate voltage and protection. Similarly, the ICA methodology is focused on the number of DERs that could be installed on a distribution circuit without exceeding equipment ratings, causing overvoltage conditions, or compromising protection schemes. Table II-2 below describes the limitations used within SCE's ICA.

35 Final Guidance, p. 3. The methodology for each IOU relies on common limitation categories (*e.g.,* thermal overloads, voltage impacts, protection coordination), but there may be some variation within each IOUs' respective ICA parameters due to operational differences—including design criteria—or available data. Further, each IOU used load flow modelling that relied upon a power flow modelling tool that evaluated multiple scenarios.

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Table II-2
ICA Methodology Limitations

Limitation Categories	Description of Limitation
Thermal Ratings	Hosting Capacity limited to the amount of DERs that may cause the loading of distribution grid devices (e.g. cable, conductor, switches) to exceed 100% of their thermal rating or planned loading limits
Protection System Limits	Hosting Capacity limited to the amount of DERs that may hinder protective devices' ability to detect and isolate faulted conditions
Power Quality Standards	Hosting Capacity limited to the amount of DERs that may cause over-voltage conditions on the primary voltage of the distribution circuits
Safety Standards	The above three limitations support the safe and reliable operation of the Distribution System[36]

These limitation categories are common among the IOUs. Parameters within each limitation category differ slightly among the IOUs due to IOU-specific design criteria or available data. As part of developing the ICA methodology, SCE collaborated with the Electric Power Research Institute (EPRI). EPRI has conducted previous research[37] in the area of PV hosting capacity and has also developed a streamlined methodology to determine a distribution circuit's hosting capacity. SCE leveraged EPRI's expertise to benchmark results and review hosting capacity parameters. The goal of this collaboration was to support the development of ICA results with considerations from previous research.

Also common among the utilities was the use of power system modeling software to perform a dynamic analysis on distribution circuits within each utility's service territory. To support this effort, SCE used Cooper Power Systems' CYME Distribution Analysis and Scripting Tool with Python modules to implement the ICA methodology and to perform an analysis that uses "dynamic modeling methods … and circuit performance data."[38] The CYME Distribution Analysis is a suite of

36 The ICA performed by SCE does not include specific safety standards as part of the dynamic modeling completed. However, the other limitations used within the ICA are aimed at maintaining the safety and reliability of the system.

37 *See* http://dpv.epri.com/hosting_capacity_method.html

38 Final Guidance, p. 3.

tools designed to model and analyze distribution systems. CYME allows users to model various operating conditions and simulate real-life scenarios. CYME is a tool used both within the power industry and by SCE to model and analyze distribution systems.

4. Integration Capacity Analysis on Representative Circuits

Consistent with the Final Guidance, SCE conducted its initial ICA on a group of 30 representative distribution circuits,[39] and extrapolated the results from the representative circuits to all the distribution circuits. The use of representative circuits allowed SCE to analyze a diverse set of distribution circuits throughout the territory. The smaller subset of circuits also allowed SCE to streamline benchmarking efforts, and concentrate resources on testing a variety of assumptions that supported development of the ICA methodology and an assessment of the results.

Using a statistical methodology known as k-means clustering,[40] a widely-used clustering technique,[41] 30 sample (or representative) distribution circuits were selected to represent the 4,636 distribution circuits within the SCE service territory. K-means clustering is a method of classifying data through a certain number of clusters, or "k-number" of clusters, which in SCE's analysis was 30 clusters. Each cluster has an arithmetic mean, or an average value, also known as the centroid of the cluster. For SCE's k-means clustering analysis, each cluster's centroid was used as the representative of that cluster. With 30 clusters, there were 30 centroids, and therefore 30 representative circuits, in which each centroid represented a subset of the 4,636 circuits. Each of the 30 representative circuits had similar dimensions (or features) to the circuits they represented, such as voltage class, climate zone, circuit loading, transformer capacity, circuit miles, customer

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39 Appendix C lists the 30 representative circuits.

40 Jain, Anil K., Data Clustering: 50 years Beyond K-Means. *See* http://www.cs.utah.edu/~piyush/teaching/kmeans50yrs.pdf.

41 SCE has previously used clustering analysis to select a group of representative circuits to support other efforts. For instance, in SCE's previous two GRCs, an analysis has been presented quantifying the impact of the replacement of aging cable on system reliability. This analysis was based on a set of representative circuits, with the results extrapolated to the rest of the system. *See* Application (A)13-11-003, 2015 SCE General Rate Case, SCE-03, Vol. 4, p. 4. Volume 4 pp. 24-29.

mix, and distribution equipment. Each dimension used was also weighted (*i.e.,* some dimensions played a larger role in the clustering analysis) to enhance the grouping of similar distribution circuits.

The selection of dimensions was important due to the relationship dimensions may have on the hosting capacity of a distribution circuit. For example, voltage class was included as a dimension for the clustering analysis because it has a direct impact on the hosting capacity of a distribution circuit. A 33 kV distribution circuit, generally, will be able to host larger amounts of DERs than a 4 kV distribution circuit. The dimensions for climate zone and customer mix are included because they are indicative of how a circuit and DERs will operate, allowing SCE to predict performance profiles that can be used to support dynamic analyses of distribution circuits. The dimensions of circuit loading and transformer capacity also determine the ability of a distribution circuit to interconnect varying levels of DERs. As the electric characteristics of long and short circuits differ, SCE included circuit miles as a dimension to provide a reasonable representation of the wide variety of distribution circuits within its service territory. As the hosting capacity is limited by thermal and protective devices in the distribution system, distribution equipment such as automatic reclosers and field capacitors were included as part of the dimensions and supported the selection of the representative distribution circuits.

Once SCE determined the 30 representative distribution circuits, CYME was used to perform the ICA on each of the representative distribution circuits. The ICA is a rigorous evaluation of each circuit's DER hosting capacities down to the line segment level. SCE then extrapolated the results of the ICA performed on the 30 representative distribution circuits to the remaining 4,636 distribution circuits down to the line segment level.[42] SCE conducted a regression analysis to

42 SCE has organized the hosting capacity (or integration capacity) into two categories because DERs have the capability of producing (discharging) energy to the grid and/or consuming (charging) energy from the grid. These two categories are discussed in additional detail within subsequent sections beginning in Section II.B.5. It is important to note the extrapolation was specific to the hosting capacity associated with DERs that produce (or discharge) energy to the grid.

determine the relationship between resistance and hosting capacity for all of the representative distribution circuits. To develop an improved representation of the potential hosting capacity at each voltage level, and due to the varying levels of loading and other characteristics across all of the non-representative distribution circuits, a single relationship was developed between resistance and hosting capacity for all representative circuits across each voltage level.

SCE also took advantage of the direct proportionality between resistance and distance to develop a means to extrapolate the hosting capacity based on distance from the substation to the remainder of the 4,636 circuits. The use of a distance to hosting capacity relationship minimized the need for extensive data validation of the non-representative distribution circuits. As there is a wide range of protection schemes and settings, the protection characteristics of each represented feeder was also considered. This approach permits SCE to provide an estimate of the potential DER hosting capacity for each of its distribution circuits at the line-segment level, as required by the Final Guidance.[43] The work performed on the 30 representative distribution circuits lays the foundation for SCE expanding the ICA to all distribution circuits in SCE's service territory in the future. In addition, future enhancements being made in SCE's GIS system will support improved efficiency of data validation efforts attributed to modeling each distribution circuit.

5. Integration Capacity Analysis Findings Using Dynamic Modeling Methods

Many factors contribute to the hosting capacity for DERs. Among those factors, the ones that heavily influence the DER hosting capacity at any one point along the distribution feeder are as follows: the distance and type of cable and conductor from the source substation; the nominal voltage of the circuit; the loading of the circuit; the rating of equipment; and the presence and settings of protective devices.

43 SCE cautions that while the 30 representative circuits can provide a representation of every circuit in SCE's distribution system, there are different operational needs and equipment ratings that are unique to every circuit. Accordingly, this representational estimate is not the same as a rigorous evaluation of a circuit, itself. As stated previously, SCE intends to analyze fully all of its distribution circuits by the next DRP.

For the purposes of SCE's ICA, every distribution circuit was divided into four line segments.[44] This segmentation supports operating flexibility (*e.g.,* transferring customers, load, or outage restoration to other distribution circuits). The segmentation into four line segments is also supported by SCE's planning guidelines related to average loading of distribution circuits, and the number of ties (between distribution circuits) generally needed to support switching required between distribution circuits under planned and emergency conditions. The factors affecting hosting capacity for DERs and the relationship to line segments is discussed in more detail below.

a) Hosting Capacity Related to DERs That Produce Energy

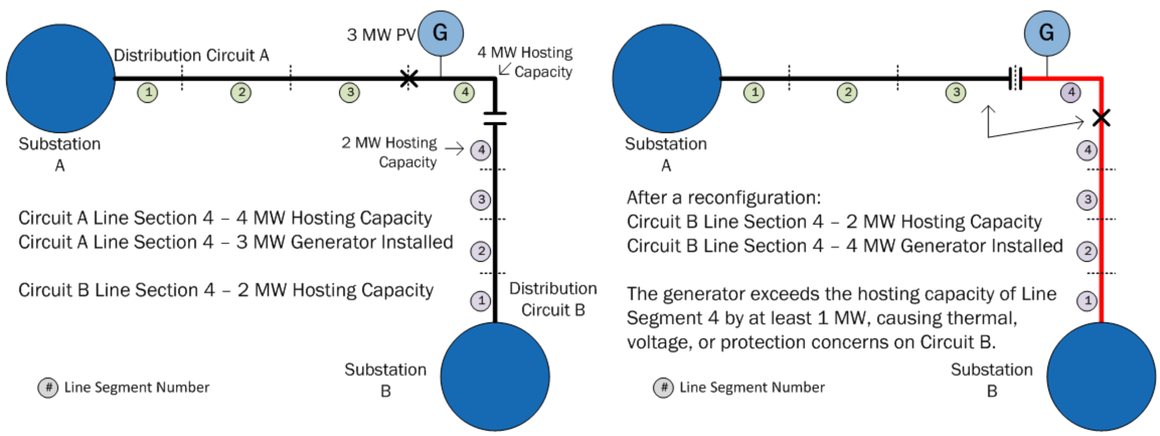
This section provides the findings from the ICA performed on the 30 representative circuits for DERs that produce or discharge energy (*e.g.,* PV) to the grid. A major factor that impacts the hosting capacity, at any point along a distribution circuit, is the resistance from the source substation to the point being analyzed on the distribution circuit. Resistance is a function of two elements: the type of conductor and/or cable and the distance to the location on the distribution circuit being analyzed. As explained in the previous section, the resistance at any point on a distribution circuit is proportional to the electrical distance from the source substation. Based on the analysis performed on the 30 representative feeders, SCE found the hosting capacity along a distribution circuit decreases as the resistance from the source substation increases. Figure II-6 shows the relationship between hosting capacity (related to discharging) and line segments. With Line Segment 4 being the line segment furthest away from the substation and the line segment with the highest resistance from the source substation, it can be seen that the hosting capacity along a circuit decreases as it approaches Line Segment 4. The highest hosting capacity values on any distribution circuit will be found on the first line segment out of the source substation, Line Segment 1. SCE notes that when distribution circuits are reconfigured to support system reliability,

44 The number of line segments or sections differs between the IOUs. This is due in part to differences in the following: design standards, planning guidelines, operating procedures and topology (e.g., electrically, geographically) of the distribution systems.

a distribution circuit's distance from a substation can be lengthened or shortened. Thus, DER (*e.g.*, renewable DG) available hosting capacity will change on permanently reconfigured circuits.[45]

In addition, there are operational challenges associated with DERs (such as distributed renewable generation) interconnected and operating along a distribution circuit away from the substation. For example, this impact may be seen when the DG interconnection to Line Segment 4 is temporarily transferred for reliability purposes to the end of a different distribution circuit where it is a greater distance from the substation. This reconfiguration poses an operating challenge because the current level of DERs sending power back to the grid could not be maintained for that segment. This example is illustrated below in Figure II-5.

Figure II-5
Reconfiguration of Two Distribution Circuits
with Hosting Capacity Concerns

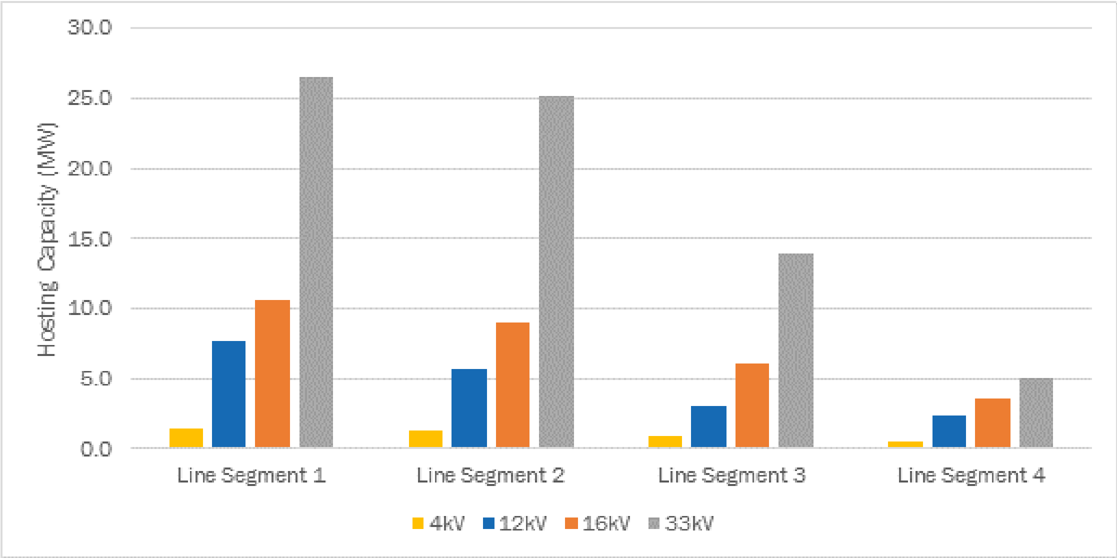


The voltage class of each distribution circuit was a major factor on the DER hosting capacity of the distribution circuits. Generally, higher voltage class distribution circuits can accommodate higher levels of DERs. As seen in Figure II-6, the 4 kV representative distribution circuits, on average, can accommodate at most 1.5 MW of generating DERs, while 12 kV circuits can

45 The distribution system is dynamic in nature and circuit reconfigurations, in addition to changes in load, can change the need for DERs at a given location between the first identification of potential locational benefits and the deployment of the DERs. This could drive a change in the net locational benefits at a specific location.

accommodate up to 7.7 MW. This trend continues to the 16 kV and 33 kV representative circuits, where on average the circuits can accommodate up to 10.6 MW and 26.5 MW, respectively. These values assume no DERs are already installed or operational on the 30 representative distribution circuit.

Figure II-6
Average Producing Hosting Capacity for the
30 Representative Circuits by Voltage Class



As illustrated above in Figure II-6, the 4 kV distribution circuits typically have significantly less hosting capacity than higher nominal voltages. The lower voltage systems (600 V to 4.8 kV) are aging systems designed to support less capacity (*i.e.,* load) than a typical distribution circuit today (*e.g.,* 12 kV). While some capacity may exist on these lower nominal voltage circuits, there are current efforts to eliminate these lower voltage systems to build or increase the capacity to that of stronger systems (*e.g.,* 12 kV, 16 kV) that would support higher levels of hosting capacity, as shown in the figure above.

The impact of the loading on the circuit also dictates the amount of discharging DER hosting capacity. Circuit loading directly relates to the amount of load DERs could offset before approaching any distribution system equipment limitations. The loading, in addition to said equipment limitations or protective settings, provides a boundary on the amount of DERs that can interconnect to a line segment where these distribution system devices are installed.

b) Hosting Capacity Related to DERs That Consume Energy

This section provides findings from the ICA that was performed on the 30 representative distribution circuits for DERs that charge or consume energy (*e.g.,* electric vehicles) from the grid. For these DERs, the main factors that determine a distribution circuit's hosting capacity are the loading of the distribution circuit, the Planned Loading Limit (PLL),[46] and equipment thermal ratings. Voltage concerns (*i.e.,* under voltage) are not a major driver of this hosting capacity as SCE's distribution circuits are designed to accommodate loading levels up to the PLL or thermal ratings of devices. For this reason, the hosting capacity for DERs that consume energy is assumed to be unaffected by under-voltage conditions and does not decrease along the line segments of the distribution circuit like the producing hosting capacity. Instead, the consuming hosting capacity is based on the utilization[47] of each distribution circuit and remains constant along the line segments, as shown in Figure II-7. For example, in the case of the 33 kV representative distribution circuit, the distribution circuit loading has already reached the PLL. Therefore, the consuming hosting capacity is 0 MW across all segments, and is lower than the 4kV representative distribution circuits' line segments' average consuming hosting capacity. Although the 33 kV distribution circuit has a higher potential to accommodate more load or consuming DERs compared to lower voltage distribution circuits, the available hosting capacity is influenced by its utilization. In this case, this results in a lower consuming hosting capacity for the 33 kV distribution circuit than the lower voltage distribution circuits. The hosting capacity is also subject to change due to the reconfiguration of distribution circuits as SCE strives to maximize the utilization of the distribution system.

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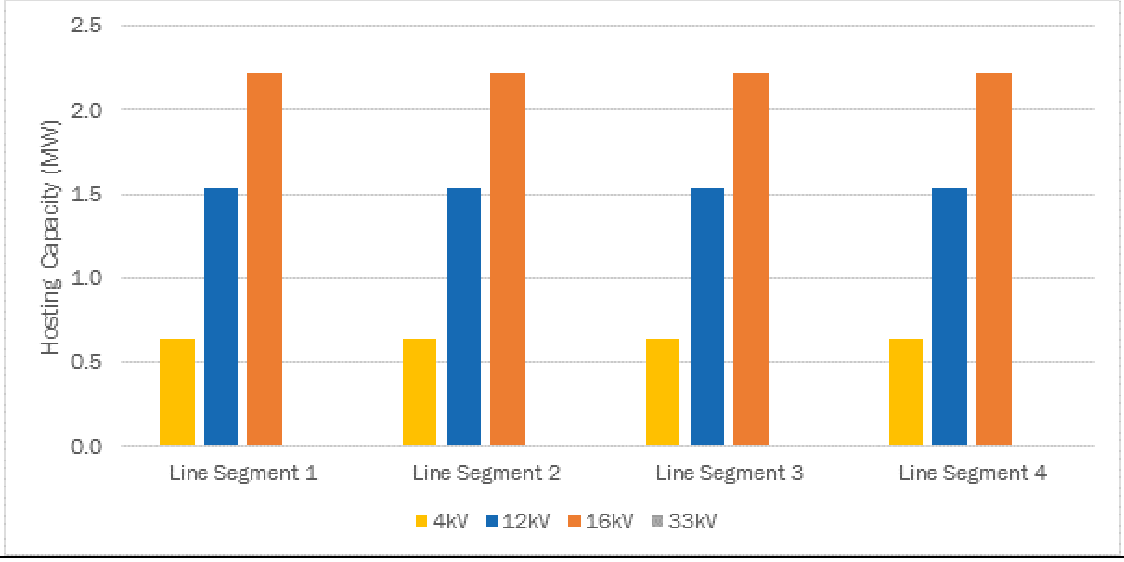
46 The maximum permissible loading capacity value of a distribution circuit.

47 Utilization is a measure of the allocated distribution circuit.

Figure II-7
Average Consuming Hosting Capacity for the 30 Representative Circuits by Voltage Class



6. Integration Capacity Analysis Assessment That Includes Any Planned Investments Within a Two-Year Period and Growth Assumptions

This section provides an assessment of the impact of growth assumptions and planned investments on the available hosting capacity with a two-year period. As noted within Section 5, the loading on the circuit impacts the hosting capacity of a distribution circuit. Based on the ICA performed on the 30 representative circuits, SCE determined that as load increases the discharge hosting capacity of a circuit also increases, assuming there are no other equipment limitations. SCE's Distribution Substation Plan (DSP) planning process forecasts customer load growth based on system needs, as well as some DER types as part of its forecast.[48] Given that some DER types reduce load growth, and some add to the load growth needs, the net load growth for a typical circuit can be very small. Based upon the current distribution planning forecast being developed by SCE, along with the minimum daytime loading assumptions built into the ICA, the impact of load growth

[48] *See* Section D.5.a of this Chapter 2 (The Current SCE Distribution Planning Process) for additional information.

was very minimal and therefore it is expected that two years of load growth will not drive significant changes in discharge hosting capacity.

In addition, some types of planned investments can also impact the discharge hosting capacity on a distribution circuit. For example, the increase in discharge hosting capacity depends upon the planned investment's ability to mitigate voltage and thermal limitations. There are various types of planned investments SCE performs throughout its distribution system. These investments vary and can include reinforcement of circuits, provision of additional capacity, upgrades to equipment to improve operating flexibility, and replacement of aging infrastructure. Some investments, such as ones related to the replacement of aging infrastructure or equipment that is reaching the end of its useful life (*e.g.,* deteriorated pole), do not impact the system capability described in the ICA. These "like-for-like" infrastructure replacement investments are necessary to maintain the reliability of the distribution system, but have no impact on the hosting capacity of the distribution system.

Other investments, such as cable and conductor replacement projects, adding additional protection and distribution field devices, or the creation of additional circuit ties, may create additional hosting capacity by increasing the system capability to accommodate DERs that charge or discharge to the grid. Whether these projects have a significant impact on the hosting capacity of a distribution circuit or line segment depends on both the size of the project and the location of the project on the distribution circuit. For example, the size of some planned investments may be very small (*e.g.,* 200 foot conductor upgrade) or large (*e.g.,* 3 mile conductor upgrade). The impact on hosting capacity between these two projects may be significantly different. Another factor to consider when analyzing the impact of planned investment on the hosting capacity of a distribution circuit is the location of the planned investment. A project that affects the backbone (or main portion) of a distribution circuit may have a larger impact on the hosting capacity of the distribution circuit than a project that will have a localized impact, such as an investment that will affect a tap line or lateral at the end of the of a distribution circuit.

As noted above, the planned investments in the next two years may create additional hosting capacity on a distribution circuit. However, the impacts on hosting capacity of the planned investments, as mentioned above, are based on the location of the project and the point of interconnection of the DERs relative to its location on the distribution circuit. The existing planned investments today were not specifically developed for the purpose of increasing hosting capacity, so they may not provide significant increases in hosting capacity, although they are needed for reliability. To provide the best opportunities for increasing hosting capacity throughout the SCE distribution system, strategic upgrades in which voltage and thermal limitations are addressed via properly sized and located infrastructure investments can facilitate higher levels of DER penetration. Investments related to grid reinforcement, as described in Chapter 7, can support increases in hosting capacity.

7. Integration Capacity Analysis Online Maps Maintained by SCE

Per the Final Guidance, SCE will publish the results of the ICA of its distribution system via online maps made available to the public. These publicly available maps will assist developers and customers to locate areas where there may be sufficient DER hosting capacity for DER projects. To meet this goal, SCE has developed a new tool, the DERiM, to publish the ICA results.[49] It will be published on SCE's website beginning July 1, 2015.

The intent of the SCE DERiM is to expand the data available to its customers and developers. The DERiM will not only incorporate the results of the ICA, but also include data regarding distribution circuitry information, such as distribution circuit names and topology, and circuit-to-substation relationships. This map is intended to serve as a new forum for SCE customers and developers to interact with SCE.[50] The DERiM contains functionality aimed at increasing ease

[49] https://www.sce.com/wps/wcm/connect/c5598823-4987-447c-a4ef-469c01d4d42a/SCE+DERiM+User+Guide_v4_WCAG.pdf?MOD=AJPERES&attachment=true&id=1432676455892&projectid=a0a304bc-ac7e-4509-a2df-1cedaba15aba&projectid=a0a304bc-ac7e-4509-a2df-1cedaba15aba.

[50] While the SCE DERiM tool does not replace SCE's existing Renewable Auction Mechanism (RAM) maps, it does provide a new mapping system that represents the required information supporting RAM and ICA.

of use by incorporating functionality that will allow the user to access the tool from a mobile device, such as an iPad or Android tablet with appropriate internet access. The DERiM also provides filtering functionality, which allows users to filter the data, and the distribution circuits displayed on the map, by multiple dimensions. This filtering functionality allows users to filter for distribution circuits of a given voltage or for distribution circuits with a hosting capacity within a user defined amount, in megawatts. SCE believes the additional data and functionality will aid its customers and developers in the siting of generation projects.

The SCE DERiM includes two types of hosting (or integration) capacities: Integration Capacity – Generation (discharge) and Integration Capacity – Load (charge). These two hosting capacities were chosen to cover the wide variety of DER types that in some cases are producers of energy (*e.g.,* solar PV, storage) or consumers of energy (*e.g.,* storage and EV charging). The Integration Capacity – Generation will typically have different values for each line segment and will vary depending upon the location of interconnection. Each map will also have an Integration Capacity – Load for those resources that consume power from the grid.

The hosting capacity for three-phase mainline portions (the backbone) of distribution circuits will be provided within DERiM. While SCE was unable to include the hosting capacity for three-phase lateral or radial sections on its DERiM prior to July 1, 2015, SCE anticipates adding this capability by July 1, 2017, in alignment with the completion of ICA in CYME for all distribution circuits. While the distribution substation capacity or its equipment can limit the aggregate hosting capacity of its child distribution circuits, the ICA on the maps will not limit hosting capacity due to substation limitations. Demonstration A (ICA Demonstration) of the demonstration and deployment projects, discussed in Section E.3.a of this Chapter, will conduct a study to determine the potential aggregate impacts of DERs at the substation level, and the study is anticipated to inform how the ICA methodology can be refined based on the findings.[51] DERiM will provide an indication of areas

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[51] *See* Appendix D for more details about the ICA Demonstration.

where transmission capacity is constrained and may impact the available hosting capacity on a distribution circuit or line segment. Within these constrained areas, the interconnection process will play a key role in evaluating the amount of DER that can be integrated.

This information is intended to help customers and DER developers assess the potential for interconnecting a variety of resources in an area, and what areas may have minimal upgrade costs or minimum distribution grid impact. This map is a valuable first step in identifying additional opportunities and can help to direct where DERs may be eligible for streamlined interconnection, but SCE cautions that its ICA data should be viewed as informative rather than definitive for all circuits that were extrapolated from the sample of 30 distribution circuits. Additionally, while this data will be updated monthly, the data can continue to change subject to reconfiguration of distribution circuits and the emergence of new resources installed in the field or within the queue.

8. Proposed Process for Updating Integration Capacity Analysis

a) Proposed Process for Maintaining Current Levels of Available Capacity

The Final Guidance requires utilities to specify a process for regularly updating the ICA.[52] SCE proposes to update the results of the ICA monthly in a similar process to that of Renewable Auction Mechanism (RAM) Maps. This process will support maintaining current levels of available capacity as circuitry is reconfigured, and will take into consideration the effects of recent interconnections and applications for DERs throughout the territory. While SCE has no current plans to update the proposed ICA methodology, SCE's Demonstration A (ICA Demonstration) may provide findings that support the need for refinement of the methodology. SCE requests that the Commission provide an opportunity for SCE to propose recommendations to the ICA for Commission approval after completion of the demonstration project or as part of the biennial DRP filings.

[52] Final Guidance, p. 4.

b) Plan to Complete ICA for Remainder of Circuits

SCE plans to conduct a dynamic analysis using CYME, at the line segment level, for all distribution circuits by July 1, 2017. Over the next two years, SCE will expand the ICA performed on the 30 representative distribution circuits described above to analyze the remainder of the 4,636 distribution circuits. This includes the development or refinement of models that reflect current system conditions. In addition, SCE has already started the work to acquire a set of tools to further automate the process by which the ICA is calculated. The ICA performed will also include any refinements to the ICA as a result of the Demonstration A (ICA Demonstration), when available.[53]

9. Integration Capacity Analysis Use with Rule 21, Rule 15, and Rule 16

The Final Guidance directs SCE to provide recommendations for utilizing ICA to support the streamlining of Rule 21 for Distributed Generation (DG) and Rule 15 and Rule 16 for Electric Vehicle (EV) load grid impacts, "with a particular focus on developing new or improved 'Fast Track' standards."[54] The ICA provides available hosting capacity down to the line segment level for distribution circuits, and is helpful in understanding available hosting capacity on primary voltage lines (from 600 V to 34.5 kV). Therefore, the usefulness of the ICA to inform processes related to EV (i.e., Rule 15, 16) and DG (*i.e.,* Rule 21) that impact both the primary and secondary services to customers will differ.

a) Tariffs Rules 15 and 16

This section considers how the ICA may be used to support and/or streamline the current assessments of grid impacts resulting from the addition of electric vehicle (EV) load, and provides information related to existing Rules 15 and 16 processes and decisions that support the addition of EV load to the grid.

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53 *See* Appendix D for more details about the ICA Demonstration.

54 Final Guidance, p. 4.

(1) Background

The current process for upgrading infrastructure to serve new EV load is performed pursuant to the following tariff rules, with the exact metering configuration dependent upon the retail rate schedule under which the EV load will be served:

Electric Rule 2 – Description of Service

Electric Rule 3 – Application for Service

Electric Rule 15 – Distribution Line Extensions

Electric Rule 16 – Service Extensions

The EV process[55] starts with the customer notifying SCE that they intend to add Electric Vehicle Service Equipment (EVSE) to their facility, in accordance with Rule 3.C.[56] For example, once the customer notifies SCE that the customer wishes to install EVSE, a service planner from one of SCE's local offices will visit the customer at their site to evaluate the adequacy of the electric grid facilities serving that location, taking into account the proposed addition of load, in accordance with Rule 2. In the event that existing facilities are not adequate to support the additional proposed load, Rule(s) 15 and/or 16, which govern distribution line and service extensions, may come into play.

In Decision 11-07-029, the Commission found that "Electric Vehicle load is designated as new and permanent load under Tariff Rules 15 and 16 and customers should be afforded the standard Tariff Rule 16 allowance to cover the costs of any required customer specific facilities."[57] Therefore, the standard Rule 15 and 16 allowance provisions that are applicable to the addition of any other permanent and bona fide load are also applicable to the addition of EV load. The

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[55] Customers will find general information and instructions on how to proceed at http://www.sce.com/ev, or they can contact SCE via a toll-free number: 1-800-4EV-INFO.

[56] SCE Tariff Rule 3 ("Change in Customer's Equipment or Operations. The customer shall give SCE written notice of the extent and nature of any material change in the size, character, or extent of the utilizing equipment or operations for which SCE is supplying electric service before making any such change."). *See* https://**www.sce.com**/NR/sc3/tm2/pdf/**Rule**3.pdf.

[57] *See* D.11-07-029, Finding of Fact No. 24, p. 79. *See also* D.13-06-014, Finding of Fact No. 1., p. 21.

allowance provisions essentially provide a credit to offset the cost of the upgrades needed to serve the new load, with customers normally being responsible for any costs in excess of the allowance.[58] These processes within Rules 15 and 16 are well established and capable of efficiently allowing for the addition of load to the grid, including load that results from EV charging.

(2) SCE Does Not Recommend Any Refinements to Rule 15 and 16

SCE believes the existing process, described above, through which customers add and install EV chargers to existing facilities, cannot be further streamlined via SCE's ICA. As discussed, the ICA provides available capacity down to the line segment level for distribution circuits or feeders. A line section may encompass a line or multiple lines in an area on a distribution circuit. There are two types of capacity related to ICA: (1) Integration Capacity – Generation and (2) Integration Capacity – Load. Since EVs act as load when being charged, the Integration Capacity – Load identified on the distribution circuit is relevant. However, the Integration Capacity – Load amount only provides the available capacity on existing primary voltage facilities (greater than 600 V). As such, the Integration Capacity – Load amount does not provide impacts related to the majority of new distribution lines extensions (related to Rule 15) and service extensions (related to Rule 16) that may be needed to serve EV load at the secondary level. SCE also has processes in place to address upgrades necessary, such as transformer and service additions, and upgrades that are based on a site specific review of the customer's projected peak demand. Furthermore, SCE recognizes that as EV load increases, it may be prudent to increase efforts to educate the public and other stakeholders about the associated impacts to the grid. SCE views educating the public on the impact of DERs on the distribution system to be an area of increasing importance.

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58 *See* D.11-07-029 and D.13-06-014 did implement an interim measure referred to as the "Common Treatment for Excess PEV Charging Costs." Under these decisions, until June 30, 2016, all residential service facility upgrade costs in excess of the standard residential allowance required to accommodate basic plug-in hybrid and EV charging arrangements are treated as common facility costs (funded by all customers) rather than being paid for by the individual EV customer.

As a result, the ICA information (via online DERiM maps) may be useful for EV customers looking for locations with sufficient capacity to interconnect EV Load to the primary voltage of the distribution system, as would be seen in fleet installations. These installations would typically be larger EV charging customers, such as workplaces or commercial EV charging installations, who would be more likely to trigger distribution circuit level upgrades (Rule 15). However, single family residential installations are typically less likely to trigger upgrades, and, if they do, they generally require service upgrades (Rule 16), which would be addressed by an actual site visit by an SCE Service Planner, as discussed above.

To help streamline the interconnection of EVs, SCE has worked diligently over the last few years to reduce the length of time it takes to complete the internal EV process. In 2009, the average time for a customer to complete SCE's end-to-end EV process was about 18 working days. Today, the average time it takes SCE to complete tasks related to the EV process is about 5 working days. This is approximately a 72% improvement, resulting from SCE's dedication to continuous improvement of the process through numerous small changes, as well the following major improvements:

- In 2011, SCE streamlined the process and established service level agreements with internal SCE stakeholder organizations serving EV customers. SCE also educated EV and charging station manufacturers, electricians, and local electrical inspection authorities about EV and SCE's EV process; and
- In 2012, SCE installed SmartConnect meters eliminating the need to change meters for the majority of customers requesting an EV rate. SCE also implemented a "first call rate change decision" process which reduced the number of times a customer contacted SCE to request a rate change.

b) Tariff Rule 21

SCE views the ICA as an important step towards the simplification of the interconnection process of DERs under the Electric Tariff Rule 21 (Rule 21). It is SCE's belief that publication of the ICA data will assist Interconnection Customers decision regarding where to site a project that will likely be able to interconnect efficiently, with limited distribution system upgrades, and with reduced study costs. However, to permit the ICA to have the full impact of simplifying the Rule 21 interconnection study processes, the incorporation of the ICA to Rule 21 must consider the essential components of safety, reliability, and power quality as outlined in the existing Rule 21 study processes.

There is an open Commission rulemaking that is reviewing Rule 21. The purpose of that proceeding is to "address the key policy and technical issues essential to timely, non-discriminatory, cost effective and transparent interconnection."[59] The Commission has directed that "[t]his [DRP] Rulemaking, and the DRPs that will be filed in 2015, do not intend to supersede policy determinations or programmatic decisions" that fall within other proceedings.[60] Accordingly, SCE does not propose to make tariff changes to Rule 21 via this DRP. Rather, SCE is mindful that such changes are more appropriately developed within the Rule 21 OIR proceeding, where all Rule 21 OIR stakeholders will have an opportunity to participate. This will also avoid the risk of conflicting Commission decisions regarding Rule 21's framework and provisions.

However, this DRP has allowed for recommendations that may streamline the interconnection process. SCE submits the following recommendations with the understanding that approval of these recommendations would still be required and vetted through the Rule 21 OIR.

(1) Recommendation

The ICA methodology SCE developed and performed for the 30 representative distribution circuits is consistent with the studies performed during the Rule 21 study process.[61] The ICA methodology and the Rule 21 study process include analysis related to power quality and reliability. Therefore, consistent with the previous discussion, SCE believes the ICA performed on these 30

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59 D.12-09-018, p. 4.

60 DRP Ruling, p. 10.

61 The thirty circuits were identified to reflect diverse system electrical characteristics within SCE's territory. For additional information please see Section B.5.

representative circuits included the underlying study components of safety, reliability, and power quality traditionally analyzed during the Rule 21 study processes. Accordingly, SCE recommends that for these 30 representative circuits, the interconnection of DERs have an expedited Rule 21 interconnection study process:

- Fast Track eligibility: One current Rule 21 Fast Track eligibility requirement is that a project have a Gross Nameplate Rating no larger than 3.0 MWs. This requirement could be refined utilizing the ICA on a line segment-specific basis.[62] This could better align Fast Track with projects that are more likely to pass Fast Track.

- Fast Track Supplemental Review Process: There may be efficiencies gained by streamlining or eliminating the supplemental review based upon the ICA. For instance, the ICA may eliminate the need to perform the existing supplemental review tests in screens N, O or P.

    - As part of the technical evaluation to determine the available Interconnection Capacity at each line segment, SCE included in the analysis the distribution circuit's daytime minimum load to verify that the power flow under daytime minimum load conditions would not create system safety and reliability conditions. Therefore, appropriately, the need to evaluate screens N and P may not be required when interconnecting DER up to the identified ICA. Similarly for screen O, interconnecting DER up to the identified ICA would not create voltage deviations capable of causing the distribution system voltage to go outside the required service and power quality requirements.[63]

SCE's other (*i.e.,* non-representative) circuits were not specifically studied in this manner. While SCE believes the use of its ICA for feeders that were extrapolated from the representative set provides a useful indication of where fast track interconnection is most likely available, SCE recommends that projects seeking to interconnect to these other distribution circuits should still require studies in accordance to the current Rule 21 procedures. SCE intends to apply the dynamic CYME modeling to all of its circuits during the next two years. Once dynamic modeling is applied to

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62 As the ICA will include circuits with which developers could seek to interconnection under SCE's Wholesale Distribution Access Tariff (WDAT), potential WDAT refinements will be reviewed to support proposal development.

63 However, consistent with the existing interconnection study process, additional technical requirements may be identified during final engineering. For example, final engineering could identify conditions where protection coordination cannot be adequately accomplished and modification or additions to the protection systems are required in order to allow for a safe and reliable electrical interconnection.

a given distribution circuit, such distribution circuit can become part of SCE's recommendations for streamlining the Rule 21 interconnection study process.

C. Optimal Location Benefit Analysis

1. Overview of Optimal Location Benefit Analysis

SCE fully supports the Commission's vision of facilitating DER deployment at optimal locations. The Final Guidance defines several pathways to determine whether a location is optimal for DER deployment. For example, a location is optimal if the DER deployment up to a certain quantity would cause no or minimal distribution grid impact. At such a location, this quantity of DERs can be interconnected without grid upgrades or with low or no interconnection cost. A location is also optimal if the DERs deployed at this location can result in lower net costs to customers, lower GHG emissions, or can enhance safety and reliability. Examples could include DERs providing a less costly solution to distribution upgrades needed to meet load growth, deferring additional infrastructure needed to maintain the reliability of service, safety, and resiliency of the grid, and power quality of service, or providing system, local, or flexible RA attributes.

In the following section, SCE describes a locational net benefits methodology (LNBM) that outlines the locational benefit components it plans to take into account and the approach it plans to follow to determine optimality.

PUC Section 769 requires the DRP proposal to:

> Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation.

As part of this evaluation, the Final Guidance directed the IOUs create an analytical framework that quantifies locational value. This framework is referred to as an "Optimal Location Benefits Analysis." This analysis is intended to specify the potential net benefit that DERs may be able to provide in a given location. In order to conduct such an analysis, the Final Guidance directs SCE to develop and file as part of its July 1, 2015 DRPs a "unified locational net benefits methodology consistent across all three Utilities that is based on the Commission approved E3

Cost-Effectiveness Calculator, but enhanced to explicitly include location-specific values . . . and at minimum, include [a series of value components specified in the Final Guidance]."[64] SCE discusses, below, how its DRP achieves the objective outlined in the Final Guidance.

2. Developing the Locational Net Benefits Methodology

a) Methodology for Optimal Location Benefit Analysis

SCE understands the Locational Net Benefits Methodology to be the foundation upon which an Optimal Location Benefit Analysis will be based. From this perspective, developing a methodology that captures how to calculate locational values of DERs is a prerequisite to perform a locational net benefit analysis. The methodology will discuss which benefits should be taken into account and how to quantify them, whereas future analysis will involve actual quantification of costs and benefits on a case-by-case basis.

SCE intends to demonstrate how the LNBM can be used in conducting a locational benefit analysis, as a part of the demonstration and deployment projects that are also proposed herein and would commence within one year of the DRP approval.

SCE describes below how the LNBM was developed jointly among SCE, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E). This methodology was also discussed with the More Than Smart Working Group, and the group's input has played a key role in the development of this methodology.

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[64] Final Guidance, p. 4. E3's calculator takes the following benefit value components into account: Energy, Losses, Ancillary Services, Emissions, Capacity, T&D avoided costs, and Avoided RPS. The Final Guidance required the utilities to include location-specific values, and the following additional value components: avoided sub-transmission, substation, and feeder-level capital expenditures (CapEx) and operations and maintenance expenses (O&M) related to forecasted load growth; avoided CapEx and O&M related to ensuring distribution voltage and power quality; avoided CapEx and O&M related to maintaining/enhancing distribution reliability and resiliency; avoided system and local-area transmission CapEx and O&M; avoided flexible RA and renewables integration expenditures; and avoided societal costs and avoided public safety costs linked to the deployment of DERs.

b) Selecting the Value Components of the LNBM

The IOUs have collaborated to develop a unified and consistent LNBM. The IOUs started with the definitions provided in the Final Guidance, which state that "benefits" can be economic, operational (from the utility perspective) or societal, and "locational benefits" are generally defined as monetary value that can be assigned to some location using a set of criteria.[65] "Locational value" was defined as monetary value that accrues to the customers and/or the utility associated with the provision of a specific service at some defined location.[66]

The Final Guidance specified that the LNBM should be based on the Commission-approved E3 Cost-Effectiveness Calculator, but enhanced to explicitly include location-specific values, and at minimum include the value components identified in the Final Guidance.[67] Here, SCE -- consistent with the other IOUs – used E3's Distributed Energy Resource Avoided Cost tool (DERAC),[68] which feeds into the Commission approved E3 Demand Response (DR) cost-effectiveness calculator, as the starting point to identify and value various locational benefits that DERs can provide. Whereas the cost-effectiveness calculators are designed to compare benefits with costs, the DERAC first calculates the value of the prescribed benefits based on avoided costs. These values then feed into the cost-effectiveness calculators.

This benefits-valuation functionality is more appropriately used as a starting point for the LNBM rather than E3's calculator. In part, as explained later, the locational values of several benefits components require a much more complicated analysis than what is represented in the E3's cost-effectiveness calculators. Also, whereas E3's calculators' values tend to be static for longer periods of time, the locational benefits calculations will be temporal, dynamic, as well as

65 Final Guidance, p. 15.

66 *Id.,* p. 15.

67 *Id.,* p. 4.

68 The DERAC model is an excel based tool developed by E3 and used to calculate the avoided costs resulting from the implementation of DR programs in the State of California. The CPUC directs all California IOUs to utilize this model when calculating the cost-effectiveness of their DR programs. Further information at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Cost-effectiveness.htm.

limited in quantity corresponding to the amount of infrastructure investment to be potentially deferred.

The DERAC provides a list of value components that are taken into account in the E3 cost-effectiveness calculator, including Generation Energy, Losses, Ancillary Services (AS), Emissions, Generation Capacity, T&D avoided costs, and Avoided RPS. However, several of these value components are quantified at the system-level in E3's tool. SCE is proposing methods to replace the system-level values with location-specific values wherever appropriate.[69] In addition, SCE has also included, in the list of benefits to be considered for LNBM, the value components that were identified in the Final Guidance, which in some cases replace the system-level value components in the E3 tool.[70] It should be noted that many of the attributes are expected to be symmetric. That is, some attributes may result in net costs while others may produce net benefits. It is likely that individual DERs will provide both benefits and costs through their attributes and both should be included in the methodology. The value components will be an input to identifying optimal locations for DERs.

3. Value Components in Locational Net Benefits Methodology

The value components included in SCE's LNBM are described below, including: the component's definition, a description of how the component is currently estimated in the DERAC tool, and the proposed methodology to be used to assess locational benefits and costs of each component. In addition to locational valuation estimates that replace the system-level calculations in the DERAC, additional adjustments will also be necessary to account for how much the DER meets localized grid needs, including the temporal and geographic coincidence of the DER attributes with the identified grid need, the dependability or predictability of the DER capacity, and the persistence of DERs within the required deferral period. These adjustments are relevant for

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[69] The location-specific valuation methods take into account individual circumstances for each IOU, and therefore, these methods might be somewhat different for each of the IOU.

[70] *See* Figure II-2 in Section A of this Chapter 2 for a picture of the value components.

estimating T&D deferral benefits as described below, but likely need to be made by adjusting estimates of the various cost and avoided cost components at all relevant locations (circuit, B-substation, and A-substation) on the distribution system when evaluating specific DER alternatives.

Lastly, not all benefits can occur or accrue simultaneously. For example, a DER that provides a distribution asset deferral benefit may be required to exclusively perform distribution grid operational or reliability functions. As such, the distribution operator will control the resource based on distribution reliability considerations, not wholesale market signals. The unit's quantified value will not accrue avoided cost benefits for energy, capacity or ancillary services requirements in the wholesale power market since the resource will function as a distribution reliability asset, not a market asset. Moreover, there may be cases in which a distributed resource serves a reliability function for only part of the year, for example during high-load summer months. In this case, the distributed resource might have access to wholesale market revenue in non-summer months, but it would not have access in the summer. Thus, the benefits quantified for the distributed resource must be considered in light of the role, services, and timing of services it provides to the distribution operator and the wholesale grid.

a) Energy Value

For use in LNBM, SCE plans to modify the DERAC tool's "avoided energy costs" component from a system-wide value to a location specific energy value. The DERAC tool calculates the avoided energy costs by applying hourly load shapes to the annual average market prices in both the day-ahead and real-time markets. Hourly load shapes are based upon historical CAISO data and market forward prices at the southern California (SP15) and the northern California (NP15) zones, and normalized for gas price volatility using gas spot-market data. The annual average market price is the product of the average market heat rate and the California Burnertip gas price annual forecast.

To change this value component to a location-specific Generation Energy component, SCE proposes to calculate the Locational Marginal Prices (LMP) at the CAISO market's pricing node (Pnode) or aggregate pricing node (APnode) to which the contemplated DER corresponds, based on available data, statistical models, and simulation models. SCE's fundamental simulation model is a full network model based on Energy Exemplar's unit constrained commitment and dispatch model Plexos. This model is used to capture the locational price differentials at any defined Pnode or APnode and the long-term fundamental prices as the sum of the three price components: energy, loss, and congestion. SCE uses statistical models to shape market quotes to hourly granularity for use in production-cost modeling.

These LMP forecasts will then be used to calculate the energy value of DERs. SCE will also take into account whether the specific DER technology provides energy to the system and therefore warrants Generation Energy benefit as a part of its total locational benefits. Similarly, if DERs such as storage require energy to operate, the costs of this energy would also be included in the calculation.

b) Losses at Transmission and Distribution Level

Line loss factors are provided in the DERAC tool and vary per utility and time of use. In the E3 cost-effectiveness calculator, losses are added to avoided generation energy costs in order to calculate avoided energy costs at the retail level.

As explained earlier, SCE plans to use the LMPs at the Pnode or APnode of a generation resource in the valuation of the resource. Therefore the locational benefit or cost of a generation resource due to the *transmission* loss has already been accounted for through the loss component included in calculating the LMP. For resources interconnecting to the distribution system, SCE plans to use the *distribution* loss factor (DLF)[71] appropriate for the interconnection voltage on the avoided energy. Furthermore, the grid-wide effect of high-levels of DER penetration is unknown, and would have to be studied through analysis of data SCE obtains in the future via demonstration and pilot projects. It is conceivable that certain DERs, such as energy storage and VGI-capable EVs, might increase losses, rather than avoid them.

71 The DLF represents the loss of energy in a distribution system when energy is provided to serve load over Utility Distribution Company (UDC) facilities; *i.e.*, the average difference between energy input and output at various distribution voltage levels.

In general, SCE manages distribution assets to reduce excessive power flow on individual components through actions such as moving circuit segments from one circuit to another. As a result, DERs are likely to have more value in reducing power flow (and losses) over a broader multi-circuit area than at the individual circuit segment area. This is another factual question that SCE plans to further explore as it collects data in the demonstration projects and elsewhere.

c) Generation Capacity

E3's DERAC tool calculates generation capacity value using a hybrid price curve that uses short-run capacity value based on market data in the early years, and long-run marginal capacity costs after the "resource balance" year. The forecasted long-run capacity cost is calculated by netting the cost of a new natural gas power plant (including environmental compliance costs) and the expected benefits derived from market revenues such as energy and ancillary services. This approach is sometimes called the CT proxy method. The calculated annual avoided capacity cost is then allocated to the top 250 highest demand hours of that year.[72] [73]

The above described DERAC tool method provides a generation capacity value without any locational differentiation. The final guidance asked the utilities to include location-specific values. Furthermore, the final guidance also asks the utilities to include flexible Resource Adequacy (RA) value component. Consequently, SCE proposes to replace the DERAC's system-level generation capacity calculations with location-specific values.[74] Under this approach, SCE takes into account

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72 SCE uses hourly loss of load expectation (LOLE) modeling to assign marginal capacity costs to the top net load hours in pricing and rate design applications. LOLE studies are both more accurate and more complex than the 250 top load hours or 250 top net load hours methods often used in calculator tools.

73 There are differences in the calculation methodology applied in the DERAC calculator between energy efficiency and demand response resources, due to different guidance from the Commission. First, long-term avoided capacity costs for energy efficiency is based on the cost of a combined cycle gas turbine (CCGT), whereas long-term avoided capacity costs for demand response is based on the cost of a simple cycle combustion turbine (CT). Second, avoided capacity costs for energy efficiency uses the hybrid short- and long-term avoided capacity cost framework described above whereas avoided capacity costs for demand responses disregards short-term avoided capacity costs and uses strictly the forecast for long-term avoided capacity costs.

74 The Commission's rules allow utilities to keep such resource valuation and selection processes, tools and calculations confidential and not share them with market participant parties.

available market prices for resource adequacy products, including price differentiation between local and system-level capacity, and also takes into account its portfolio requirement for certain type of resources in specific locations as well as the cost of new entrant capacity. In addition, SCE can ascribe value based on the attributes that the resource provides. For example, resources that provide local capacity, system capacity as well as flexible RA value[75] would get a higher capacity valuation compared to resources that only provide system capacity benefits and are not flexible.

d) Ancillary Services

Currently, avoided Ancillary Services (AS)[76] costs are calculated in the DERAC model as one percent of the wholesale energy price. SCE believes that this is not an appropriate way to ascribe AS value to DERs, especially on a location specific basis.[77]

SCE derives its AS price forecast using a series of econometric and statistical models that capture current and future grid conditions, energy and fuel prices, customer demand and historical AS prices. The AS price forecasts also take the incremental flexibility need created by intermittent resources, through their expected build-out schedule and generation profiles, to inform increases in price levels and intraday volatility. SCE co-optimizes energy and AS value using fundamental production-cost simulation models. The difference between the energy-only value of the resource and the co-optimized energy and AS value is identified as the AS value of the resource. To the extent this value is not already reflected in the above described capacity value, it can be ascribed to the resource that is capable of providing the ancillary services.

75 SCE is currently working on a flexible RA price curve which will be applied in the same fashion as the system/local curves for non-flexible resources. The flexibility adder also informs a portion of the calculation of avoided renewable integration costs via the renewable integration cost adder, addressed in more detail in section 8. It should be noted that only dispatchable resources will be eligible for the flexibility premium.

76 Examples of ancillary services products include regulation up, regulation down, spinning reserve, and non-spinning reserve.

77 Unlike energy price, AS prices are not defined at the nodal level. Therefore, there is no locational difference in the AS prices in the same AS region per se. However, the expected energy needed to support the ancillary services is valued against the LMPs, which include a locational component. In this sense, the locational benefits/costs have been accounted for in SCE's valuation.

e) Transmission and Distribution Capacity CapEx and O&M

In the current E3 cost-effectiveness framework, the marginal cost (in $/kW-yr) for distribution and sub-transmission from each utility's latest General Rate Case (GRC) is used to calculate transmission and distribution capacity investment deferral value. These avoided costs are then allocated to the hottest hours of the year based on temperatures in each climate zone.

To better capture the deferral value of planned capital expenditures, SCE recommends a new methodology to value T&D avoided costs in ($/kW) for DERs using the Real Economic Carrying Charge (RECC) method. The RECC method calculates the net present value of the capital investment deferral over an identified deferral time-frame. The potential capital investment to be deferred and the deferral timeframe are based on the amount of DERs that can reasonably be deployed to address the specified grid need, applied over the timeframe of the deferral, not a single year. This methodology values the benefit of investment deferral from customers' perspective and includes return on investment and utility taxes. Therefore, the methodology to calculate this valuation component includes the IOUs' planned project-specific deferral values and captures the geographical and temporal characteristics for each project.

SCE conducts an Annual Transmission Reliability Assessment (ATRA) for SCE's portion of the California Independent System Operator Corporation (CAISO) controlled grid. ATRA evaluates the performance of SCE's transmission system to determine transmission constraints and identify upgrades needed to maintain reliability.[78] The ATRA is performed in parallel with CAISO's annual Transmission Planning Process (TPP).

There are various public processes that determine the required transmission projects in the CAISO controlled grid. Using the cost of traditional grid investment and by identifying specific system characteristics (or needs) driving the need for the transmission projects, a deferral value or avoided cost can be calculated.

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[78] A.13-11-003, 2015 SCE GRC, SCE-03, Vol. 3, pp. 9-10.

The identification of traditional grid projects for sub-transmission, substation (distribution), and feeders (distribution) typically occur as part of the Load Growth Planning Program.[79] Projects under the Load Growth Planning Program are needed to increase system capacity and are identified in both the Transmission Substation Plan (TSP) and the Distribution Substation Plan (DSP). The TSP typically identifies system requirements and projects associated with SCE's sub-transmission System. The DSP identifies system requirements and projects associated with SCE's Distribution System. A goal of both 10-year plans is to identify system requirements needed to ensure timely planning of traditional grid projects to serve both the sub-transmission and the Distribution Systems while maintaining service reliability. When planning for traditional grid investments, the goal is to minimize overall costs for customers by investing in proactive solutions while optimizing existing capacity on the system. The current process of identifying system requirements and traditional grid investments will remain intact for both plans. However, using the cost of traditional grid capital expenditures and by identifying specific system characteristics (or needs), a deferral value or avoided cost can be calculated. There is an interrelationship of transmission system planning and associated upgrade needs, and distribution system planning and upgrade needs, and SCE takes that interrelationship into account.

SCE anticipates that where DERs avoid or defer traditional grid investments, some operating expenditures may be avoided or deferred. Traditional capital investments include either replacement of existing equipment or installation of new equipment. For traditional capital investments that are replacing or upgrading existing equipment, the installation of DERs will not completely avoid the ongoing operating expenditures; however, the avoidance or deferral of new equipment may result in avoiding certain types of operating expenditures. The type of activity that can be avoided or deferred may include inspections and maintenance on the system along with related expenses that are driven by the deferred project. These avoided costs will consider the

[79] A.13-11-003, 2015 SCE GRC, SCE-03, Vol. 3, p. 1.

potential O&M cost over the useful life of the newly installed equipment. Those costs will be added to deferral value as calculated using the RECC methodology.

As stated at the introduction to this section, the estimated transmission and distribution deferral value attributed to DERs will be based on the DER's load reduction capacity that is coincident with specific grid needs at specific locations on the distribution grid. For a portfolio of DERs that would be used to defer some planned grid project, the DER portfolio's load reduction capacity would thus be adjusted to reflect the likelihood that the DER will avoid the capital investment based on its characteristics and different locational scenarios. These adjustments would be based on a level of locational certainty, temporal certainty, the DER's peak coincidence to grid needs, and the ability to be dispatched to respond to the distribution system's needs, respectively. After these adjustments are made to the DER capacity, the T&D deferral valuation can be applied. Additional grid reinforcements may be necessary to balance load and demand where DERs create incidental issues that require mitigation, such as where ICA capacity is negatively impacted in the same area as where the load growth expansion is identified. In that case, the locational benefits must also consider the cost for other upgrades necessary to realize the capital deferral.

f) Avoided Distribution Voltage and Power Quality CapEx and O&M

Avoided distribution voltage and power quality capital expenditures and operating expenditures is not an avoided cost category within the DERAC tool. Therefore, this value component is an additional category that will be considered within the Locational Net Benefits Methodology.

The identification of traditional grid projects for distribution voltage typically occurs as part of the sub-transmission VAR Plan (component of TSP) and the Distribution VAR Plan. Both VAR plans include the installation of capacitor projects throughout the SCE grid to supply reactive power[80]

[80] Note that the reactive power investments identified in the plans are also required to avoid demand from the transmission grid. Thus, the reactive power deferrals need to meet the requirements of the overall system, including the transmission system.

needs and support maintaining adequate voltage. The purpose of both the Distribution and Sub-transmission VAR programs are to provide sufficient reactive support at the Transmission level to provide for bulk power voltage stability, as well as provide for local reactive and voltage support. With the addition of the Locational Net Benefits Methodology framework, SCE has the opportunity to utilize DERs to meet system requirements indicated in the Sub-transmission VAR Plan and Distribution VAR Plan. However, within the planning process, there needs to be a method of accounting for projected reactive power deliveries that could be reliably provided and aggregated at the sub-transmission level. Assuming that this method of accounting is developed and implemented, using the cost of traditional grid capital and by identifying specific system characteristics (or needs), a deferral value or avoided cost can be calculated using the RECC method discussed in Section C.3.e above. Avoided operating expenditures will reflect the considerations noted in Section C.3.e above, and will be added to deferral value as calculated using the RECC methodology.

SCE does not have a program or traditional capital investments related to power quality. Therefore, there does not currently exist an opportunity to defer projects in the area of power quality.

g) Avoided Distribution Reliability and Resiliency CapEx and O&M

Avoided distribution reliability and resiliency capital expenditures and operating expenditures is not an avoided cost category within the DERAC tool. Therefore, this value component is an additional category that will be considered within the Locational Net Benefits Methodology.

The identification of traditional grid projects associated with distribution reliability are part SCE's Infrastructure Replacement (IR) programs. The goal of the IR programs is to reduce the impact of aging infrastructure on the reliability and safety of the grid by replacing equipment before it fails in the field.[81] As noted within the 2015 GRC, the age of many types of equipment on the

[81] A.13-11-003, 2015 SCE GRC. SCE-03, Vol. 4.

Distribution System is increasing and the likelihood of failure increases as a function of age. While there may be a few atypical projects (*e.g.,* 2nd service to remote service) unrelated to age with potential for deferral, the addition of DERs will not improve reliability due to an additional point of failure (created by the DER) without additional design and infrastructure considerations such as a microgrid, and inability of the technology to ride through system events while maintaining grid safety. Where DERs can serve as an alternative to traditional utility distribution system investment, using the cost of traditional grid capital and by identifying specific system characteristics, a deferral value or avoided cost can be calculated using the RECC method discussed in Section C.3.e above. Assuming DERs can reliably function as an alternative to a traditional investment, avoided operating expenditures will reflect the considerations noted in section C.3.e above, and will be added to deferral value as calculated using the RECC methodology. There may be other opportunities to improve reliability metrics with certain types of DER projects (*e.g.,* microgrids), but that will need to be further evaluated to determine the value received from such systems. The use of a microgrid to meet reliability needs is a demonstration project that is noted within this DRP, and can support validating the improvements a microgrid can make to reliability.

SCE does not have a program or traditional capital investments related to resiliency. Therefore, there does not currently exist an opportunity to defer projects in the area of resiliency. Both distribution reliability and resiliency can be explored through SCE's various demonstration projects, which can then yield more informed valuation approaches.

h) Avoided Environmental Costs (GHG Emissions)

The DERAC tool calculates GHG avoided costs (from carbon emissions) by using a forecast from Synapse Energy Economics. GHG prices from 2013 through 2030 are based on the Synapse mid-level price forecast and also used in the 2009 Market Price Referent (MPR) update. GHG prices from 2008 through 2012 are extrapolated based on the Synapse forecast. GHG prices after 2030 are assumed to remain flat as in the 2009 MPR.

In comparison, SCE calculates GHG avoided costs based on blended results from the GHG auctions and the secondary markets, with a fundamental outlook derived from several vendor's positions on supply and demand. Quotes of California compliance instruments' futures are also taken into account where there is sufficient liquidity, and blended to the fundamental outlook over time. This forecast is then used in modeling future power prices as explained earlier. Therefore, the resulting generation energy forecast includes embedded GHG costs.

Under SCE's approach, DERs will receive the value of avoiding GHG emissions via the value of avoided generation energy costs. When being compared to conventional resources, DERs get the benefit of not have any combustion-related GHG compliance obligation and corresponding costs, thereby increasing the valuation of DERs to the extent they displace conventional generating resource emissions. [82]

i) Avoided RPS

The DERAC model calculates an avoided Renewables Portfolio Standard (RPS) cost by multiplying the renewable premium by the amount of reduction in RPS compliance requirement as a result of reduced load. The RPS standard is assumed to stay constant at 33% post 2020.[83] The renewable premium is calculated as the difference between the avoided cost of marginal renewables ($/MWh) less the sum of market energy value of renewables ($/MWh) plus the emissions cost ($/MWh) and the capacity value of renewables ($/MWh). These values are simply inflated annually at the inflation rate.

Avoided RPS cost is a system-level value only. In other words, any reduction in load anywhere in SCE's system will have the same impact from a RPS compliance standpoint. SCE is planning to use the DERAC tool's methodology, using inputs as described above but with SCE's values for the inputs (*i.e.,* DERAC marginal cost of renewables less SCE's energy price forecast,

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82 Regarding EVs, GHG costs to electric customers may also be reduced or avoided through regulatory means such as with the issuance of additional GHG credits or reduction in compliance obligation related to electricity as fuel in the transportation sector. This value, pending regulation, can also be taken into account.

83 Governor Brown, in his inaugural address, stated that he proposes to increase the electricity derived from renewable sources from 33% to 50%. (Inaugural Address Source: http://gov.ca.gov/news.php?id=18828). Details have yet to be defined, but once it is defined, the "avoided RPS" component should be updated.

which includes the cost of GHG, less SCE's capacity price forecast) in the LNBM calculations. This calculation will provide an avoided RPS value which differentiates on location, in the spirit of the LNBM methodology.

j) Avoided Renewables Integration Costs

This is a new value component specifically listed in the Final Guidance. It is not included in the DERAC tool.

Certain DERs can reduce the cost of integrating intermittent renewable generation by providing the operational flexibility that the system operator needs in order to firm-up the intermittent resources serving load. By providing such flexibility, these DERs avoid the costs that the system operation may otherwise have incurred in acquiring flexible resources. However, to the extent this benefit is the same as avoided flexible RA or ancillary services value discussed earlier, it would be appropriate to only count this benefit once.

Generally, SCE does not attribute the benefit of avoiding renewable integration cost with respect to any DERs that are interconnected behind the customer meter. Renewable integration requires flexible resources that the utility and/or the CAISO can control to manage intermittent load. It is possible that in the future, EVs might provide such functionality, and if so, SCE will recommend in a future DRP cycle to attribute the benefit of avoided renewable integration costs to EVs. Similarly, if the use of DR resources evolves such that they are used to manage intermittency, SCE will similarly recommend to attribute avoided renewable integration costs to such DR resources. Similarly, SCE does not attribute the benefit of avoiding renewable integration cost to any In-Front-of-the-Meter (IFOM) energy storage (ES), because to the extent IFOM ES avoids renewable integration costs, this benefit is captured in the form of avoided flexible RA and in the value of ancillary services provided which are discussed earlier.

It should be noted that certain DERs increase the renewable integration costs, rather than avoid them. This is because the DERs might add additional intermittency and require additional flexible resources to counteract this intermittency. For such DERs, it is more appropriate to assess a cost, or a negative benefit, in the form of a renewable integration cost adder (RICA). SCE captures such RICA with respect to solar and wind resources.

SCE plans to utilize the commission's methodology to calculate the RICA, which was adopted as an interim methodology pursuant to Decision 14-11-042.[84] The RICA calculation captures the incremental flexible need created by IFOM RPS resources via a fixed component and a variable component. The fixed costs include costs associated with meeting new and perhaps existing long-term flexible capacity requirements. The variable component captures the incremental operational cost to support intermittent renewable resources. Operational costs include ancillary services costs for offsetting intra-hour variability (reg-up/down) and flexible ramping capacity costs for offsetting intra-hour forecast errors. The variable cost component is different for solar and wind: $4/MWh vs. $3/MWh, respectively.[85] The RICA calculation is included as a cost cash flow in valuing intermittent resources which create the need for incremental flexible capacity.

k) Avoided Societal Costs

Increasing DERs as a replacement for central station fossil fuel generators can potentially reduce the emissions of criteria pollutants, which in turn might result in benefits to society. Similarly, utility actions in the electricity sector can help reduce emissions in other sectors, such as transportation or industrial sectors of the economy. Also, development of new DER technologies can spur economic growth and innovation, leading to improved standards of living, higher tax receipts, and an increase in housing values. DERs may even encourage better land use management.

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84 This is currently being updated in the LTPP. On May 29, 2015, SCE filed a Report in.R.13-12-010, on the modeling results of the six cases and E3 calculation of the integration adder. *See* "Report of Southern California Edison Company On Renewable Integration Cost Study For 33% Renewables Portfolio Standard."

85 The calculation details can be found here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K313/143313500.PDF.

However, SCE believes that a credible method does not exist to equate such societal benefits into avoided costs for utility customers.[86] For the foreseeable future, the attribution of these benefits to DERs is best performed on a qualitative assessment, as any quantitative means will be highly speculative.

l) Avoided Public Safety Costs

SCE is unable to identify realizable value that can be attributed to improvements in public safety due to DER deployment. Improved public safety information,[87] where readily available, can be supportive in prioritizing DER alternatives based on a qualitative assessment.

4. Calculation of Net Benefits Require Costs to Be Also Taken into Account

Locational Net Benefits is the calculation, generally represented in form of the net present value (NPV), to compare benefits net of costs for the options being evaluated. The value components identified earlier represent the various benefits that could potentially accrue to the utility customers. However, to calculate "net" benefits, the costs that the utility customers would incur in obtaining the necessary products and services from DERs also must be considered. Therefore, to the extent costs will be paid by SCE's customers, SCE plans to take such costs into account while calculating the net benefits of any DERs. Examples of such costs include fixed payments or incentives provided to deploy the DER, on-going payments for products and services purchased from the DERs, for any DER technology that increases GHG emissions in the utility's portfolio, the increased costs of compliance with the California Air Resources Board's (ARB's) GHG cap and trade program, debt-equivalence costs (if any), and any other costs that the utility customers incurs related to the DER.

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86 If a framework emerges that allows utilities to quantify societal benefits that utility customers create by their actions, SCE would be able to reflect it in the benefits valuation methodology.

87 Refer to Ch. 5, Safety Considerations.

5. Identifying Optimal Locations and Maintaining Ongoing Updates

SCE agrees that DER deployment should be facilitated in optimal locations, and doing so will likely require providing some signals regarding the benefits of DER deployment in such locations. SCE will conduct an indicative analysis using high value benefit components (*e.g.,* distribution deferrals or energy value) to identify locations where DERs are likely to provide the most benefits. SCE would also attempt to categorize/rank those locations based on the relative benefits DERs are likely to provide. SCE plans to publish a list of such optimal location areas, likely in form of "heat-maps," that would help to direct DER deployment to those areas and/or leverage existing resources. SCE plans to update this list after the conclusion of its annual distribution planning process. Such optimal location areas might span multiple circuits or substations. Once these optimal locations are identified, SCE could explore methods to encourage DERs in those areas.

SCE may need to address several issues regarding the identification of optimal locations. For example, the assumptions underlying the analysis to identify optimal locations can change rapidly, and when they do, the locations might no longer be optimal. SCE will need to determine how to inform the DER development process while retaining the flexibility to adjust those areas based on updated information on changes in customer demand and grid modifications made for reliability purposes.

6. Integrating LNBM into Long-Term Planning Initiatives

LNBM can be integrated into long-term planning initiatives through its inclusion in various forecasting processes. LNBM will have a fundamental impact on a utility's forecast of the load the utility needs to serve as well as load-side and supply-side resources it can count on. These changes to the various forecasts are likely to have an equally profound impact on long-term planning initiatives such as the CAISO's TPP, the Long Term Procurement Plan (LTPP) and the CEC's IEPR. SCE plans to use the LNBM as described in this filing and modify it and its components in future DRP submittals.

7. Using Distribution Planning Review Group to Promote Stakeholder Transparency in Planning Activities

It is SCE's desire to be transparent in sharing results of its distribution planning activities to facilitate, enable, and animate DERs. These results will inevitably involve confidential and market sensitive information, which, if made public and shared with DER developers, could harm SCE's ability to acquire DERs performing grid functions at the lowest possible cost to its customers. At the same time, non-market participant parties have a legitimate interest in reviewing SCE's distribution planning activities related to DER deployment.

In the power procurement context, the Commission uses the Procurement Review Group (PRG) process for the review of the utilities' procurement activities in the wholesale energy and emissions markets.[88] Utilities' PRGs comprise eligible non-market participant parties, who must each sign a non-disclosure agreement with the utility prior to receiving the utility's confidential, market-sensitive procurement information.[89] Utilities conduct periodic meetings with the PRG participants to review their procurement activities in the wholesale markets. The Commission has consistently acknowledged the value of PRGs by ordering their continued use, so that they and interested stakeholders can continue to provide consulting review to utilities on their procurement activities.[90]

SCE recommends that the Commission similarly establish a Distribution Planning Review Group (DPRG) consulting process to review how SCE applies the Commission-approved distribution investment deferral framework discussed in Chapter 8(C)(1). Such a group would be made up of eligible non-market participant parties who would sign non-disclosure agreements with each utility

[88] PRGs were initially established in (D).02-08-071 as an advisory group to review and assess the details of the IOUs' overall procurement strategies, RFOs, specific proposed procurement contracts and other procurement processes prior to submitting filings to the Commission as an interim mechanism for procurement review.

[89] Examples of such participants include the Commission's Energy Division, ORA, TURN, and environmental groups. D.06-12-030 further defined "market participant" and "non-market participant" parties.

[90] *See* D.02-08-071, D.02-10-062, D.03-12-062, D.04-12-048, and D.07-12-052.

and be able to review the utilities' distribution planning process with respect to compliance with this deferral framework. Market participants would not be eligible to participate in this group, and would not be able to obtain information that would be classified as confidential and market sensitive information at the distribution level. This process would enable the Commission and the utilities to strike a balance between transparency and contemporaneous discovery, on the one hand, and protection of confidential information, on the other.

D. DER Growth Scenarios

1. Overview of DER Growth Scenarios

To facilitate integration of DERs on the distribution system in a manner that attempts to minimize overall system costs and maximize utility customer benefits from investments in DERs, new methods of assessing the impacts of DERs on the grid, in varying volumes, are necessary. In this chapter, SCE presents the three CPUC mandated 10-year DER growth scenarios that project potential growth of DERs through 2025 at a system level. SCE then develops an expected geographic dispersion at the distribution feeder level. Finally, SCE assesses possible impacts of these dispersions on distribution planning.

The Final Guidance states that "[T]he Utilities shall develop three 10-year scenarios that project expected growth of DERs through 2025, including expected geographic dispersion at the distribution feeder level and impacts on distribution planning."[91] The Commission also provided criteria for each scenario, which served as the foundation for development of the scenarios.   To meet these requirements, this section contains the following subsections:

- Section 3 provides an overview of the three 10-year scenarios.
    - Scenario 1, discussed in Section 3(a), provides a growth scenario that adapts the IEPR "Trajectory" case.

[91] Final Guidance, p. 5.

- Scenario 2, discussed in Section 3(b), provides a growth scenario that adapts the IEPR "High Growth."
    - Scenario 3, discussed in Section 3(c), is based on very high growth in DERs.
- Section 4 describes the method for allocating DERs down to the distribution circuit level.
- Section 5 illustrates the geographic dispersion of DERs based on the scenarios.
- Section 6 identifies the impacts to distribution planning based on the results of the identified scenarios.

2. SCE's Three 10-Year Scenarios

a) Scenario 1

Scenario 1 "[a]dapts the IEPR 'Trajectory' case for DER deployment for distribution planning at the feeder level, down to each line section."[92] The Integrated Energy Policy Report, or IEPR, Trajectory case is a forecast of energy production and consumption in the state of California. The IEPR Trajectory case is developed in a biennial proceeding at the California Energy Commission (CEC).

This Trajectory case is intended to reflect a modest base scenario for California's resource and infrastructure planning to anticipate future energy infrastructure needs. In the May 2014 ACR issued in the LTPP, the CPUC explained that the Trajectory case is:

[92] Final Guidance, p. 5.

> [T]he control scenario for resource and infrastructure planning, designed to reflect a modestly conservative future world with little change from existing procurement policies and little change from business as usual practices. This scenario assumes an average level of economic and demographic growth, and as such, uses the Mid load case for the 2013 IEPR [California Energy Demand (CED)] forecast. This is paired with the Mid AAEE scenario[93] from the 2013 IEPR CED forecast. The Trajectory scenario assumes no incremental demand-side small PV or CHP beyond what is already embedded in the 2013 IEPR CED forecast. For supply-side resources, this scenario assumes the default for conventional additions, no net growth in supply-side CHP, the default for storage and DR, a commercial-interest driven RPS portfolio maintaining the 33% standard in 2024, no nuclear retirement, a low level of renewable and hydro retirement, a mid-level of retirement for other resource types, the default for imports, and accounts for existing procurement authorizations.[94]

SCE incorporated the IEPR Trajectory case's assumptions into its Scenario 1 without modification. This is intended to provide a base case against which other scenarios can be compared. However, the IEPR Trajectory case does not include a forecast for storage and demand response. For storage, SCE utilized the procurement targets established by the CPUC in its LTPP decision D.13-10-040, which is the most recent CPUC decision addressing storage procurement. For demand response, SCE utilized the demand response assumption used in the LTPP's version of the Trajectory case. Within Scenario 1 is the assumption that about 2.3 million EVs will be on California's roads by 2024.[95]

The figures for Scenario 1 are shown in the table below. The figures include estimates of state-wide amounts of DER deployment by type in calendar 2025 for various technologies. The units are MW of capacity, MW of installed nameplate capacity, or GWh of energy (for each technology).

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93 California Energy Commission Staff Final Report, California Energy Demand 2014-2024 Final Forecast, Vol. 1, January 2014 (CEC-200-2013-004-V1-CMF), pp. 81-101.

94 *See* Rulemaking (R).13-12-010, Attachment to the Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 Long Term Procurement Plan and 2014-15 CAISO TPP, dated May 14, 2014, pp. 35-36.

95 California Energy Commission Staff Final Report, California Energy Demand 2014-2024 Final Forecast, Vol. 1, January 2014 (CEC-200-2013-004-V1-CMF), pp. 41-45.

Table II-3
Scenario 1 Statewide Amounts of DER Deployment by 2025

Growth Type	Scenario 1
Base Load	60,109 MW
Solar PV (nameplate AC)[96]	4,812 MW
AAEE (annual)[97]	22,565 GWh
Demand Response[98]	2,176 MW
CHP (annual)[99]	13,877 GWh
EV (annual)[100]	4,877 GWh
Storage (D&C)[101]	654 MW
Storage (T)[102]	700 MW

b) Scenario 2

Scenario 2 "[a]dapts the IEPR 'High Growth' case for DER adoption but also incorporates additional information from Load Serving Entities (LSEs), 3rd party DER owners, and DER vendors."[103] In the May 2014 ruling issued in the LTPP, the CPUC explained that the High Growth Case (also called the High DG scenario):

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96 Solar PV is shown in nameplate installed AC capacity since that is the total amount that could be produced. Although in any given moment, Solar PV may produce a lesser value, installed capacity is the most straightforward measure to show how much Solar PV there is.

97 Additional Achievable Energy Efficiency (AAEE) is shown as annual energy (GWh) savings to be realized in the target year.

98 Demand Response is the total capacity (MW) that can be called upon at once.

99 CHP is shown as the total energy (GWh) that is assumed to be produced in the target year.

100 EV is the total energy (GWh) that is assumed to be consumed in the target year. Note that the peak for EV charging is expected to be produced sometime between 10 PM and 6 A.M.

101 Storage (D&C) is energy storage connected at the distribution and customer level. Over the course of the year and allowing for charging losses, storage will be a net-zero energy producer.

102 Storage (T) is energy storage connected at the transmission level. It is also a net-zero energy producer.

103 Final Guidance, p. 5.

> . . . explores the implications of promoting high amounts of distributed generation (DG), which may imply more aggressive pursuit of customer-sited distributed generation programs, and a shift in RPS procurement towards favoring wholesale distributed generation projects located near load pockets. This scenario diverges from the Trajectory scenario by assuming a high incremental amount of demand-side small PV and a low incremental amount of demand-side CHP beyond what is embedded in the 2013 IEPR CED forecast, and uses a High DG driven RPS portfolio maintaining the 33% standard in 2024. This scenario's impact on the transmission system is effectively explored as part of the CAISO TPP's Policy and Economic studies.[104]

SCE generally incorporated the IEPR High Growth case's assumptions into its Scenario 2 without modification.[105] As with Scenario 1, SCE used the energy storage procurement targets from D.13-10-040 assuming they would all be in service by 2024. SCE selected this assumption to remain consistent with the Commission's guidance as established via D.13-10-040. Unlike the Trajectory case, the High Growth case provided a demand response assumption, which SCE incorporated into its Scenario 2. However, SCE found a need to "adapt" Scenario 2 away from the existing IEPR High Growth case's assumption regarding solar PV and increased the assumption level. SCE did this because, based on recent data reflecting current solar PV adoption, it was appropriate to increase the assumption. Accordingly, SCE used the IEPR "mid-case" assumption, which is a slightly more aggressive growth scenario as compared to the High Growth scenario.

To meet the direction to incorporate additional information from LSEs, DER owners, and DER vendors, SCE reached out to the service list of R.14-08-013 on April 3, 2015 to solicit input, which was requested in written form by April 17, 2015. This service list includes over 200 entities, many of which are or represent LSEs, DER owners and/or DER vendors. SCE received one response to the written request, but it did not provide information related to changes to Scenario 2.

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[104] R.13-12-010, Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 Long Term Procurement Plan and 2014-15 CAISO TPP, dated May 14, 2014, p. 37.

[105] While not stated explicitly in the CPUC's description above, High DG uses the mid-high AAEE forecast. California Energy Commission Staff Final Report, California Energy Demand 2014-2024 Final Forecast, Vol. 1, January 2014 (CEC-200-2013-004-V1-CMF), pp. 81-101.

The figures for Scenario 2 are shown in the table below. The figures are SCE's estimates of state-wide amounts for calendar 2025 for the various technologies. The units are MW of capacity, MW of installed nameplate capacity, or GWh of energy (as appropriate for each technology).

Table II-4
Scenario 2 Statewide Amounts of DER Deployment by 2025

Growth Type	Scenario 2
Base Load	60,109 MW
Solar PV (nameplate AC)	5,498 MW
AAEE (annual)	36,068 GWh
Demand Response	3,570 MW
CHP (annual)	21,132 GWh
EV (annual)	7,026 GWh
Storage (D&C)	654 MW
Storage (T)	700 MW

c) Scenario 3

Scenario 3 is "[b]ased on very high potential growth in the use of DERs to meet transmission system needs, resource adequacy, distribution reliability, resiliency, and long-term greenhouse gas (GHG) reductions, with key inputs drawn from achieving goals."[106] Section 1.c.iii of the Final Guidance provides that such goals include:

1. Governor's 2030 Energy Policy Goals:
    a. 50% share of electricity from renewables[107]
    b. Reduction of petroleum used by cars and trucks by half
    c. Reduction of electricity used in existing buildings by half and the development of cleaner heating fuels
2. Zero Net Energy Goals
3. 2030 GHG reductions identified in the Air Resources Board's 2014 Scoping Plan

[106] Final Guidance, p. 5.

[107] SCE has assumed that the goal of 50% share of renewables includes all renewables, not simply those renewables that are DERs.

Update

4. Governor's Zero Emission Vehicle Action Plan
5. Commission's 2020 Energy Storage Requirements
6. Commission's Demand Response (DR) Goal of 5% of peak load managed by DR
7. Reduction in the cost and frequency of routine outages
8. Reduction in the cost and improved responsiveness to major or catastrophic events[108]

To address goal 1.a, SCE developed a new forecast for solar PV that reflects a significant increase as compared to Scenarios 1 and 2. SCE assumes 13,792 MWs of solar PV in this case, as compared to 5,498 assumed in Scenario 2.[109] This assumption attempts to capture an aspirational goal regarding solar PV adoption and integration.

To address goals 1.c, 2, 3, and 6, SCE developed AAEE, Demand Response, and CHP assumptions that it believes will assist in achieving these goals.

- For AAEE, SCE used the high case from the IEPR 2013 CED forecast.[110] The IEPR 2013 CED forecast reflects a slightly more aggressive assumption as compared IEPR High Growth scenario.
- For Demand Response, SCE used 10% of the Scenario 1 managed load, reflecting a more aggressive approach compared to the 5% used in Scenario 2.
- For CHP, SCE used the assumption adopted by the Incremental High Case established in the 2014 LTPP.[111] SCE viewed this assumption as an aggressive and aspirational assumption.

To address goal 4 and 1.b, SCE assumed there would be 3.7 million EVs on the road by 2024. This assumption is the same EV assumption used in Scenario 2. While this is greater than

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108 Final Guidance, p. 5.

109 13,792 MW of solar PV is about 23% of 2025 base load. Existing DER-connected solar PV is currently approximately 5%.

110 California Energy Commission Staff Final Report, California Energy Demand 2014-2024 Final Forecast, Vol. 1, January 2014 (CEC-200-2013-004-V1-CMF), pp. 81-101.

111 *See* R.13-12-010, Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 Long Term Procurement Plan and 2014-15 CAISO TPP, dated May 14, 2014, pp. 15-16.

the Governor's Zero Emission Vehicle Action Plan goal, which targets 1.5 million zero emission vehicles on California roadways by 2025, SCE applied this greater assumption to reflect the purpose of Scenario 3, which is to address very high DER growth potential.

To address goal 5, SCE created an assumption that tracks a percentage increase in storage as compared to Scenario 2 that is consistent with the percentage increase of solar PV between Scenario 2 and Scenario 3. This reflects a substantial increase as compared to the Commission's 2020 Energy Storage Requirement.

Regarding goals 7 and 8, namely reduction in the cost and frequency of routine outages and reduction in the cost and improved responsiveness to major or catastrophic events, SCE does not believe that the amount of DERs assumed by SCE, by itself, can meet the goal's objectives. Rather, it is the manner in which DERs are deployed that can facilitate the goals. Accordingly, these goals will be met via a DER's technical abilities to meet grid reliability needs, and support from grid modernization efforts which will better enable such DER deployment.

For Scenario 3, SCE's estimates of state-wide DER deployment amounts for calendar year 2025, by technology type, are shown in Table II-5 below. Scenarios 1 and 2 are also listed in Table II-5 for comparison. The amounts are shown in MW of capacity, MW of installed nameplate capacity, or GWh of energy, as appropriate for each technology type.

Table II-5
Scenario 3 Statewide Amounts of DER Deployment by 2025

Growth Type	Scenario 1	Scenario 2	Scenario 3
Base Load	60,109 MW	60,109 MW	60,109 MW
Solar PV (nameplate AC)	4,812 MW	5,498 MW	13,792 MW
AAEE (annual)	22,565 GWh	36,068 GWh	36,655 GWh
Demand Response	2,176 MW	3,570 MW	5,100 MW
CHP (annual)	13,877 GWh	21,132 GWh	32,112 GWh
EV (annual)	4,877 GWh	7,026 GWh	7,026 GWh
Storage (D&C)	654 MW	654 MW	1,543 MW
Storage (T)	700 MW	700 MW	1,651 MW

For Scenario 3, SCE's estimates of DER deployment amounts within SCE's service territory for calendar year 2025, by technology type, are shown in Table II-6 below. Scenarios 1 and 2 are also listed in Table II-6 for comparison. The amounts are shown in MW of capacity, MW of installed nameplate capacity, or GWh of energy, as appropriate for each technology type.

Table II-6
Scenario 3 SCE Territory Amounts of DER Deployment by 2025

Growth Type	Scenario 1	Scenario 2	Scenario 3
Base Load	27,019 MW	27,019 MW	27,019 MW
Solar PV (nameplate AC)	1,636 MW	1,905 MW	4,770 MW
AAEE (annual)	10,536 GWh	17,031 GWh	17,243 GWh
Demand Response	1,265 MW	2,087 MW	2,981 MW
CHP (annual)	6,350 GWh	8,576 GWh	13,612 GWh
EV (annual)	2,422 GWh	3,395 GWh	3,395 GWh
Storage (D&C)	270 MW	270 MW	637 MW
Storage (T)	310 MW	310 MW	731 MW

3. Method for Allocating DER Penetration at the Distribution Circuit Level

a) Overview

The three scenarios identified in the Final Guidance and described in the previous section are allocated to individual distribution circuits by DER category, as described in this section, so that the impact of the level of DER penetration reflected in the three scenarios on distribution planning can be assessed. The DER categories included in this allocation process are solar PV, CHP, electric vehicle (EV) loads, additional achievable energy efficiency (AAEE), demand response (DR) and energy storage (ES).

In general, the process that SCE has used to perform this allocation is based on DER potential. That is, SCE has attempted to identify the types of customers who have the greatest economic potential and/or interest in installing the various forms of DERs, inventoried the distribution of these customers across SCE's individual distribution circuits, and then allocated the quantity of DERs to distribution circuits in proportion to the amount of customers with DER potential on these circuits. As a result, the DER allocations described in this section are unconstrained by any limitations of the existing distribution grid to accommodate the DERs. Thus, the DER allocations are suitable for the purpose identified in the Final Guidance of identifying distribution planning impacts, but should not be regarded as an actual forecast of DER penetration. Areas with limited integration capacity and high DER potential may preclude development of some of the DERs projected in the scenarios, or alternatively may identify areas where additional distribution investment is needed to accommodate DER growth.

The DER scenarios and allocations are "top down" estimates, which may not accurately align with a realistic level of DER penetration for individual circuits. This is a particular issue where the DER scenario is aspirational and exceeds the DER potential that SCE has used to allocate the DERs. In some cases, the DER allocations imply more customers of a particular type than actually exist on the associated circuit. As such, the resulting impacts of the DER scenarios should be regarded as indicative. Over time, the methods applied in making this DER allocation must be refined to better align a "top down" perspective with a "bottom up" view of how policy choice can influence DER potential.

As described below, in some cases SCE has performed customer-specific studies to identify DER potential, and then aggregated the results of these studies to the distribution circuit level. In other cases, SCE has relied on broader potential studies allocated to individual circuit or has used historical adoption locations to scale the DER projects. In addition to allocating DERs to individual circuits, it is necessary to develop an hourly load shape for each DER technology so that the impact of the DERs at times of both high and low distribution circuit loading can be identified. The approach SCE used to develop these load shapes is also described below.

b) Solar PV

The overall projections of solar PV systems in the three DER scenarios were allocated by first splitting the projections between residential and commercial installations using an internal forecast. SCE forecasts the residential and commercial market segments separately, although using similar techniques. The models predict customer solar PV adoption using a set of input variables, such as historical adoption and economic potential. This resulted in about 75% of the cumulative solar PV being installed in the residential segment by 2024. For residential customers, economic potential was developed using a study of individual customer potential savings performed for SCE by Caltech. Based on their study, savings (economic) potential was the main predictor of Solar PV adoption.

For commercial customers, SCE used a similar approach, relying on historical adoption and economic potential. The commercial customers were clustered (binned) based on historical usage and North American Industry Classification System (NAICS) code. The process involved two parts: first identifying optimal PV sizing for each customer and then applying this size to the savings equation to determine the economic potential. Once the system-wide forecasts were determined, they were allocated down to circuit level based on the underlying customer type distribution across the distribution circuits. The resulting DER forecasts by circuit were then scaled to match the amount of solar PV in each of the DER scenarios. Solar PV load shapes were based on an internal estimate used for load forecasting. The resulting hourly solar PV output represents a typical pattern of energy production, and is not adjusted to reflect the amount of solar PV output that would be considered as dependable for planning or resource adequacy purposes.

c) Energy Storage

Energy storage is particularly challenging to allocate to circuits, because of the considerable uncertainty in how energy storage may be used in future customer or developer applications. For the purpose of making an allocation, SCE assumed that the scenario projections of energy storage will be distributed proportionately to the penetration of commercial solar PV systems, under an assumption that the primary driver of energy storage investment will be to allow these commercial customers to "firm" the output of their solar PV systems in order to minimize exposure to peak demand charges. To the extent that the energy storage system has additional energy capability beyond what is needed to offset occasional periods of reduced solar output (such as partially cloudy summer days), SCE assumes that the storage devices will either operate during circuit peak, or will be available to distribution operations to be operated when needed for circuit reliability. Thus, there is no need to establish a fixed load shape for energy storage devices. The energy storage devices are assumed to have a four hour duration at their capacity rating.

d) AAEE

The scenario projections of AAEE are based on a CPUC-commissioned potential study prepared by Navigant Consulting, which has details of specific aspects of the modeling documented in their referenced report.[112] The results include projected amounts of AAEE for 5 scenarios, the first three of which are used in SCE's scenario analysis (mid low case, mid case, and the mid high case for Scenarios 1, 2, and 3 respectively). The variables in the modeling with the greatest impact on the results were: (1) compliance rate of codes and standards; (2) amount of incentives; and (3) amount of emerging technologies.

To facilitate allocation of the energy savings to the distribution circuits SCE developed an annual energy shape for each sector, based on SCE's 2014 program mix. SCE assumed that the AAEE energy shape will be similar to the existing utility program annual energy shape by sector. SCE allocated the amount of AAEE across distribution circuits in proportion to the amount of actual sector energy consumption for each circuit.

e) DR

SCE has an inventory of its existing DR program participation by B-station (typically a 66 kV to 12 kV substation) level. The scenario projections of DR penetration were spread to B-station in proportion to the existing distribution of program participation. Then circuit allocations were made, based on the proportions of circuit load within each B-station area, by sector.

The DR annual shape was generated based on the forecast participation of existing (dispatchable) programs. Each program has its unique availability constraints that were applied to the highest load days of the year. Without perfect foresight, the forecast program dispatch is somewhat uncertain. As an approximation of the program dispatch, the amount of generation capacity from each program was subtracted from the top load hours of the year (approximately 200 hours). The programs are actually dispatched based on existing market conditions.

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[112] 2013 California Energy Efficiency Potentials and Goals Study Final Report, February 14, 2014. *See* http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M088/K661/88661468.PDF.

f) EV

SCE's distribution planners already use an allocation of EV loads in the annual distribution system planning process. SCE uses the same case as used in Scenarios 2 and 3 in the DSP process.

The existing allocations are adjusted proportionately for each of the scenario projections. In SCE's analysis, Scenario 1, the assumption that about 2.3 million EVs will be on California's roads by 2024, is equivalent to SCE's low case and Scenarios 2 and 3, the assumption that about 3.7 million cars will be on California's roads by 2024, is equivalent to SCE's mid case. Both are described in SCE's 2015 GRC testimony Exhibit 09 at pp. 266-272.

g) CHP

To assess the impact of increased combined heat and power (CHP) resources on its distribution grid, SCE estimated the potential for more CHP by performing an economic analysis of those businesses, identified by NAICS codes that typically have CHP systems on site.

This total potential estimate was scaled to the scenario values and was then allocated to distribution system locations corresponding to the locations of businesses in the identified NAICS categories across SCE's distribution circuits.

4. Geographic Dispersion of DERs

The preceding section discusses how DERs were dispersed down to the distribution circuit level for each of the developed scenarios. Worksheets of the dispersed DER growth for each scenario over a ten-year period can be found within the DER Growth Worksheets.[113] The DER Growth Worksheets include the circuit or feeder name, the aggregate amount of DER growth by circuit, and the aggregate amount of DER growth available at the circuit peak time. The amount of DER coincident to the circuit peak period was used to identify how much DER capacity may be used to meet a circuit's peak loading requirements, and ultimately any loading requirements for its

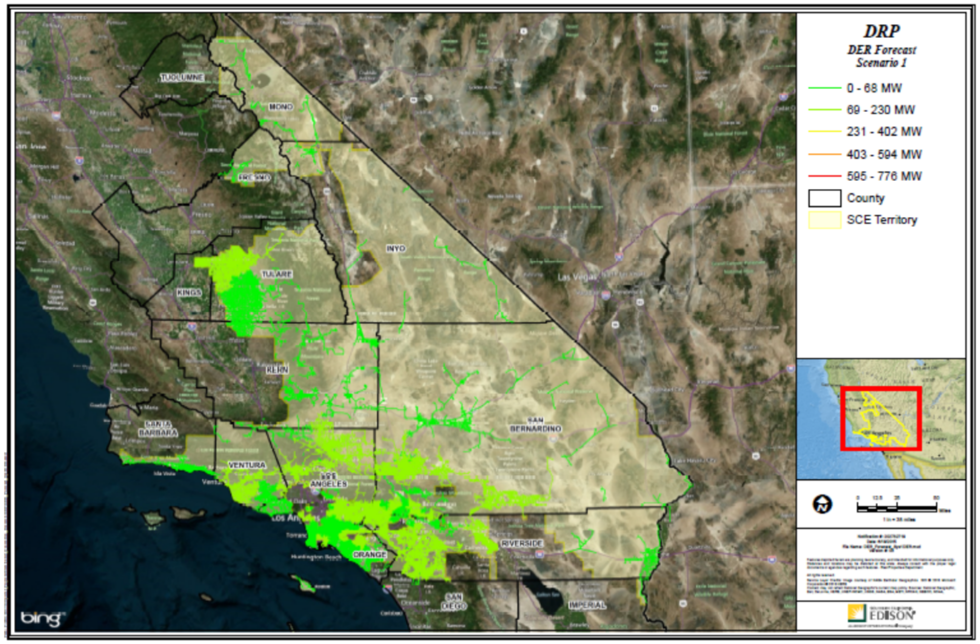
[113] Appendix J: DER Growth Scenarios Worksheets.

parent substation. The following three figures illustrate the geographic dispersion of DER[114] aggregated at the subtransmission system level[115] (for visualization purposes) by 2025 for each scenario, and the changes in levels of DER growth across the scenarios.

114 The illustration depicts the maximum DER potential, and not the amount of the DER coincident to the circuit peak.

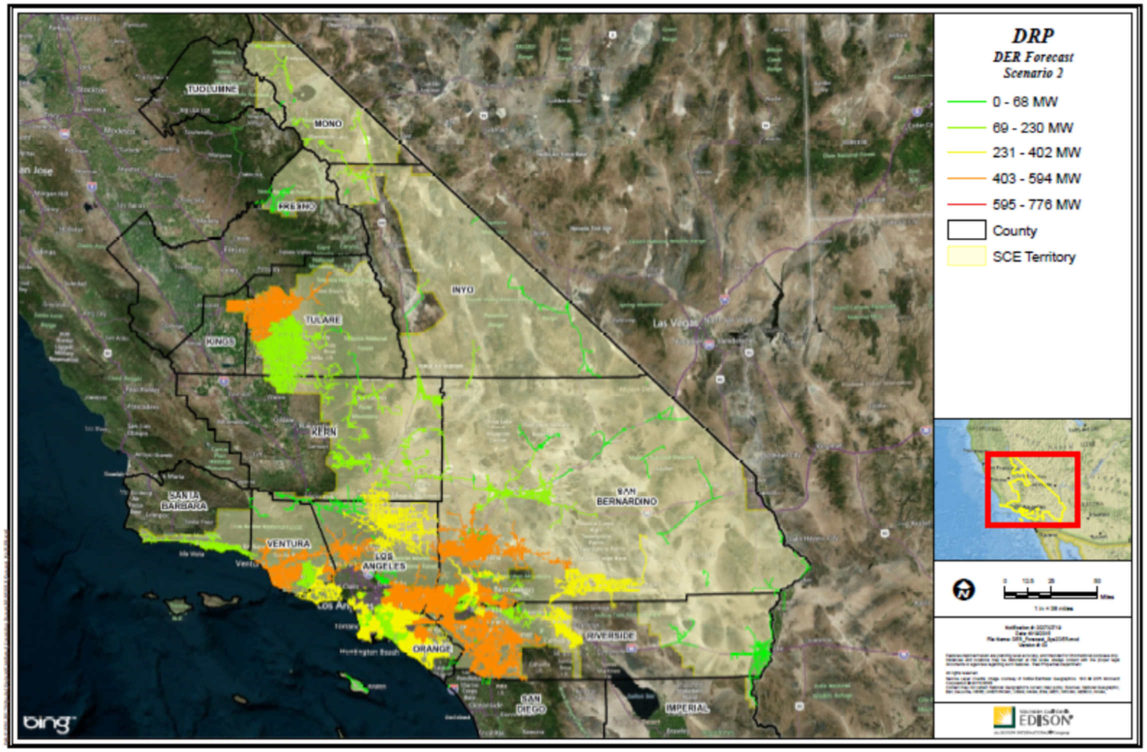
115 *See* Table VIII-15, SCE System Classifications and Transformation Voltages.

Figure II-8[116]
Subtransmission Level View of Geographic Dispersion of Scenario 1
Based on Maximum DER Potential



116 Text box in bottom right of image states: "Features depicted herein are planning level accuracy, and intended for informational purposes only. Distances and locations may be distorted at this scale. Always consult the proper legal documents or agencies regarding such features. Real properties Document. All rights reserved. Service Layer Credits: Image courtesy of NASA Earthstar Geographics SIO © 2015 Microsoft Corporation © 2015 HERE. Content may not reflect National Geographic's current map policy. Source: National Geographic, Esri, DeLome, HERE, UNEP-WCMC, USGS, NASA, ESA, METI, NRCAN, GEBCO, NOAA, increment P corp."

Figure II-9[117]
Subtransmission Level View of Geographic Dispersion of Scenario 2
Based on Maximum DER Potential



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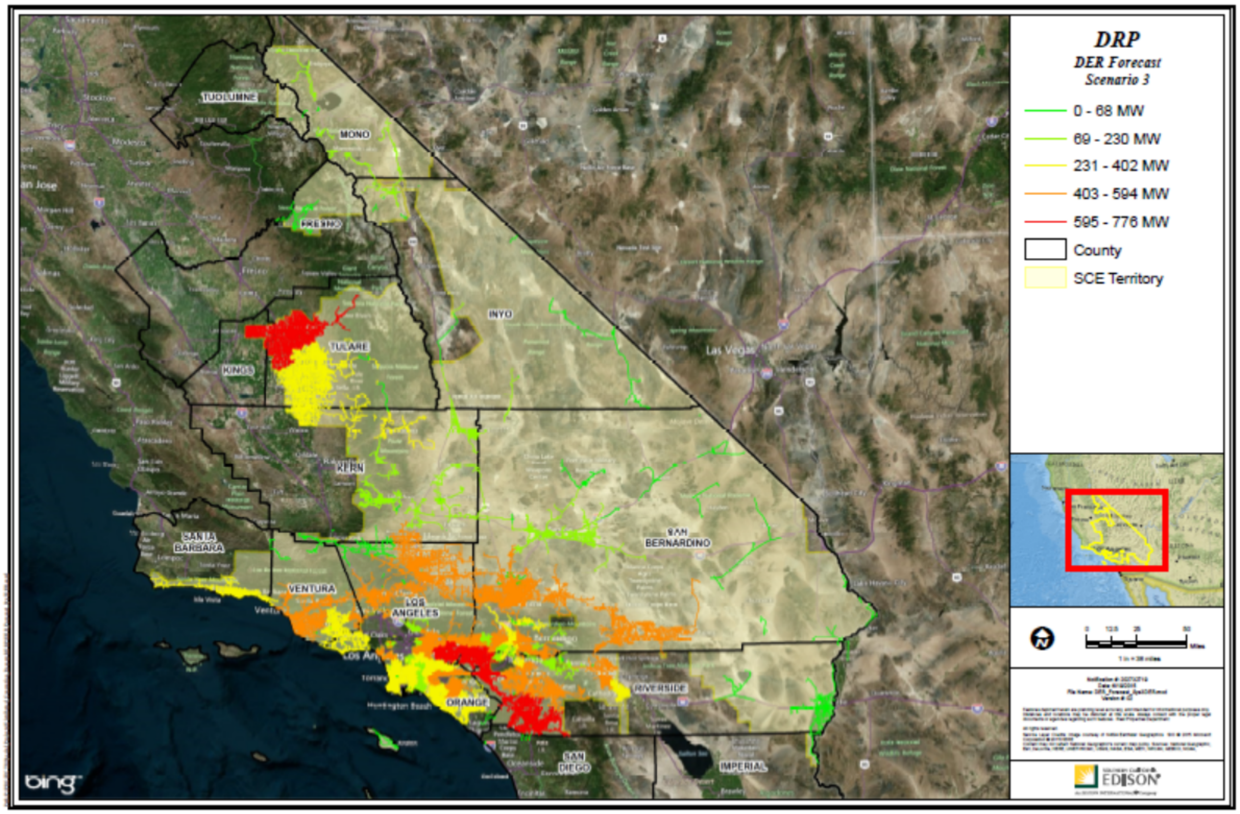
[117] Text box in bottom right of image states: "Features depicted herein are planning level accuracy, and intended for informational purposes only. Distances and locations may be distorted at this scale. Always consult the proper legal documents or agencies regarding such features. Real properties Document. All rights reserved. Service Layer Credits: Image courtesy of NASA Earthstar Geographics SIO © 2015 Microsoft Corporation © 2015 HERE. Content may not reflect National Geographic's current map policy. Source: National Geographic, Esri, DeLome, HERE, UNEP-WCMC, USGS, NASA, ESA, METI, NRCAN, GEBCO, NOAA, increment P corp."

Figure II-10[118]
Subtransmission Level View of Geographic Dispersion of Scenario 3
Based on Maximum DER Potential



[118] Text box in bottom right of image states: "Features depicted herein are planning level accuracy, and intended for informational purposes only. Distances and locations may be distorted at this scale. Always consult the proper legal documents or agencies regarding such features. Real properties Document. All rights reserved. Service Layer Credits: Image courtesy of NASA Earthstar Geographics SIO © 2015 Microsoft Corporation © 2015 HERE. Content may not reflect National Geographic's current map policy. Source: National Geographic, Esri, DeLome, HERE, UNEP-WCMC, USGS, NASA, ESA, METI, NRCAN, GEBCO, NOAA, increment P corp."

As shown in the three figures above, the areas with the lowest levels of penetration are green and those areas with the highest levels of penetration are red.[119] The geographic dispersion for Scenario 1 shows relatively lower levels of DER growth (less than 230 MW) spread across the territory. These lower levels of DER growth were expected because scenario 1 was the "Trajectory" case. Scenario 2 illustrates higher levels of DER growth (from 403 MW to 594 MW) across certain areas of several counties including Riverside, San Bernardino, Orange, Los Angeles, Ventura, and Tulare. In Scenario 3, the higher levels of DER growth (greater than 595 MW) were primarily concentrated in Riverside and Tulare counties, and a small area of San Bernardino and Los Angeles Counties. As section B(2)(b) of this Chapter explains, the current levels of DG deployment and the circuits with the highest levels of penetration are concentrated in the low and high deserts of Riverside and San Bernardino counties. While Scenario 3 showed relatively higher levels of growth (from 403 MW to 594 MW) in those areas, they were not the most heavily impacted.

5. Impact on Distribution Planning

This section provides a high-level review of possible impacts of the above-described DER growth scenarios on SCE's distribution system planning efforts. The increased penetration of DERs, as noted by the three scenarios, may impact the following three areas: the current distribution load growth forecast (and planned capital investments), the ability for distribution facilities to handle heightened penetration, and the ability to forecast and assess current levels of DERs. While the scenarios should not be regarded as an actual forecast of DER penetration, SCE recognizes that the DRP is an iterative and transformative process, and that improvements in forecasting DER growth, at the feeder level, will help to inform future planning efforts. The three scenarios developed are helpful in understanding how the utility may be impacted in the future due to increased penetration of DERs.

119 Given the three figures demonstrate DER growth aggregated at the subtransmission level, both the density of distribution of circuits within a region and the amount of DER growth allocated to each, influences the dispersion seen across the counties.

The following provides a roadmap of the subsections covered within this section:

- Section (a) provides background on the current SCE distribution planning process and the process of identifying capital investments to meet load growth needs.
- Section (b) describes the evolution of the distribution planning process and the potential for DERs to defer traditional grid investments.
- Section (c) highlights the potential impact of the DER growth scenarios on Distribution System Load growth and consequently traditional grid investments
- Section (d) discusses the impacts of increased DER penetration on Distribution System equipment.
- Section (e) identifies the new planning capabilities needed due to increased penetration and to accurately consider the future impacts of DERs into planning.

a) The Current SCE Distribution Planning Process

SCE's distribution system is planned and designed in accordance with SCE's approved design standards and criteria to ensure that SCE can serve forecasted customer load growth safely and reliably, within established loading limits. The Distribution Substation Plan (DSP) results from SCE's annual distribution planning process that identifies the distribution system requirements as they relate to serving projected customer load growth. As communicated within the 2015 GRC, forecasts prepared as part of the DSP include the following growth components: anticipated customer load, the effects of lighting standards, Plug-in Electric Vehicles (PEV), and Photovoltaic Generation.[120] Using these growth components, a 10-year load forecast is developed and compared against loading limits to identify potential projects to address equipment overloads. Project alternatives are also evaluated and selected that take reliability, cost effectiveness, and operational flexibility of each solution into consideration.[121]

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120 The current distribution planning process is explained in greater detail within the SCE's 2015 GRC. *See* http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/C7A588821E58E50E88257C210080F142/$FILE/SCE-03%20Vol.%2003.pdf, pp. 8-15.

121 *Id.*

b) Evolution of the Planning Process and Anticipated Planning Impacts

The current distribution planning process is centered around safely and reliably providing the one-way flow of power to serve SCE customers. While SCE has integrated DERs into the DSP forecast, the use of DERs in support of system requirements (the ability to reliably serve customer load growth) has not historically been a primary focus of the distribution planning process. As new technologies and additional data become available, SCE will enhance the distribution planning process to include the tools and methodologies being developed, and improved DER forecasting techniques. As the DRP process continues to evolve, DER growth scenarios and their allocations down to the substation and circuit level can be used to provide a high-level understanding of the potential for DERs to defer traditional distribution projects. As DER integration tools mature, SCE believes that DERs can be capable of meeting system requirements and will likely reduce the need for some distribution system projects (or traditional grid investments) in the future. The next section provides an assessment of the potential impact of the DERs from the three scenarios on the current distribution system load growth.

c) Assessment of Impact on Distribution System Load Growth

(1) DER Growth Assumptions Used for Assessment

This section assesses the possible impacts that increased the DER deployment of the three scenarios will have on distribution planning. This assessment assumes the following:

1) DERs will materialize according to the growth scenarios' allocation to each distribution circuit, as discussed in Section D(3) of this Chapter 2;
2) DERs are available for use by the utility at the time of circuit peak (DERs are coincident to circuit peak); and
3) DERs can reliably and consistently meet system requirements.

This assessment takes a largely optimistic approach by assuming all DERs will be capable of meeting distribution system requirements. However, once DER portfolios are used as alternatives to grid investments, additional guidelines will be needed to determine how DER growth will be applied to future forecasts (and impact traditional grid investments). Some of these guidelines may include: ensuring DERs are installed in the location of need, verifying that they can be relied upon consistently at the time of the peak to meet the need, ensuring DERs will be available throughout the deferral period of a traditional grid investment, and the ability for SCE to monitor and/or control DERs in order to meet the needs of the distribution system. Even with these guidelines in place, it will take time to acquire and construct DERs, and for grid modernization investments (*e.g.,* controls, monitoring) to be in place. With both the guidelines above and the appropriate grid modernization investments in place, this will likely result in the ability for DER alternatives to supplant traditional grid investments identified by the distribution planning process. In addition, although all of the tools and methodologies identified in future phases of the DRP are not yet established, SCE's assessment of the impact on distribution planning assumes all the necessary tools, methodologies, and guidelines are operational.

The DER allocation methodology described in Sections D.3 and D.4 of this chapter provides an opportunity for SCE to test new ways (*e.g.,* DER shapes) for allocating DERs down to the circuit level. Furthermore, SCE's current planning process does not currently include CHP, AAEE, and Energy Storage. While SCE does include Solar PV, SCE's distribution forecast utilized a different load shape or profile than the developed scenarios to forecast dependability of the resource in meeting system needs. As a result of less data being available at the time of development, the load shape used for PV in SCE's current forecast is more conservative than the shape developed for the growth scenarios as part of this DRP. Therefore, these scenarios have higher amounts of DER resources assumed than the distribution planning process. This again demonstrates that, while the growth in the developed scenarios differ from the growth in SCE's distribution current forecast, the three scenarios were meant to be indicative of the potential impacts due to increased DER penetration.

SCE's goal is to improve the distribution planning process by accounting for the various DERs, and their anticipated dependability, but without compromising reliability in serving SCE customers. In addition, open forums to discuss forecasting related issues (*e.g.,* dependability of resources) may be helpful in future planning of DER growth. This will support future forecasting to better incorporate greater levels of DER penetration throughout the system. Given the highlighted assumptions above, the sections that follow describe the specific impacts found.

(2) Assessment of Impact of Scenarios at the System Level

SCE began this assessment by evaluating the current 10-year distribution system growth rate to establish a baseline. SCE's current[122] 10-year growth rate for the distribution system is approximately 1.4%. The allocation of DER for each scenario results in a decrease in the distribution system projected load growth rate for each successive scenario. The table below illustrates the impact of each DER scenario on the 10-year growth rate at the SCE system level.

Table II-7
Impact of Each DER Scenario on the 10-Year Growth Rate
at the SCE System Level

	Current	Scenario 1	Scenario 2	Scenario 3
10-year Growth Rate	1.4%	1.0%	0.9%	0.2%

Each scenario provides a potential of DERs required to reduce SCE system level distribution forecast. Scenario 1, 2, and 3 also result in an impact on the growth rate, reducing the total system load growth forecast by 0.4%, 0.5%, and 1.2%, respectively.

(3) Assessment of Impacts at the Distribution Substation Level

While the assessment above considers the macro-level impact of the scenarios to the distribution system, there is also an impact at local level (*e.g.,* distribution substation). Load growth at the individual substation level will vary from the system level growth rate. Each substation's growth rate can either be above or below the system level growth rate based on local factors such as demographics, vacancy rates, open land, and local economic conditions. The scenario analyses show that some traditional capital upgrades will still be needed to support customer load growth at some substations. In order to meet local substation needs with DERs, the DERs would need to be

[122] The growth rates provided are from SCE's 2015-2024 Distribution Substation Plan which was still under-development as of June 1, 2015.

placed in the project needs areas and would need to exhibit specific performance relative to the local need.

In addition, the scenarios demonstrated that DER growth has a higher likelihood of reducing load growth at distribution substations in the latter years of the distribution plan. Load growth rates may vary from year to year, depending on the known load growth projects documented to increase demand in an area. The impact of the DER scenario allocation increases as the 10-year plan progresses, and the likelihood of project reduced distribution load growth at distribution substations increases. The next section describes the potential impact of the scenarios specifically at the project level.

(4) Assessment of Impact to Distribution Projects

For each scenario, a high-level analysis was performed to determine the potential for deferral of load growth-driven traditional distribution capacity upgrades and new distribution circuits. For example, the assessment demonstrated that a distribution substation project to increase capacity at Alessandro Substation (located in Riverside County, east of March Air Reserve Base) in 2018 could be deferred 2 years based on Scenario 1, 3 years based on Scenario 2, and deferred outside of the 10 year plan based on Scenario 3. The scenarios indicate varying futures and possible impacts at the identified substation. However, a DER will need to actually materialize in the field, be properly located, and operated specifically to local needs in order to effectively defer projects like the one at Alessandro Substation. The example above also highlights that changes in forecasts over time, due to varying growth rates, can lead to changes in the duration of project deferral. This uncertainty in the duration of the deferral benefit from year-to-year, can lead to differing DER deferral value.

While DERs may defer projects throughout the system, the lower medium voltage systems (4 kV or lower) are aged and have various concerns related to power quality, weaker short circuit contribution, and limited flexibility to support the switching of load and generation during trouble periods. These lower voltage systems have limited capacity and were designed for the systems of the past, which typically contain substation equipment that is obsolete. Therefore, increased DER penetration at these distribution facilities could cause the need for additional or accelerated capital upgrades or costs while at the same time trying to drive deferral. For that reason, these lower voltage systems were not considered as part of this analysis because of the limited opportunities they create for DER integration. Elimination of these aging facilities, and converting them to higher voltage (*e.g.,* 12 kV) facilities, can create opportunities to support increased penetration, and possibly reduce costs related to limited capacity. Programs identified within the 2015 GRC such as the 4 kV Substation Elimination Program[123] may allow for increased penetration and support the integration of DERs as alternatives to traditional grid investments while meeting long-term system needs.

d) Assessment of Impact on Distribution System Facilities

As noted earlier, the distribution planning process is primarily focused on determining system requirements as they relate to safely and reliably serving customer load growth over the next 10 years. However, integrating higher levels of DERs could cause system issues (*e.g.,* voltage impacts, thermal overloads, desensitization of protection) that may impact customer reliability. DERs could stress current distribution facilities and their ability to reliably serve power to SCE customers. For instance, the integration of large amounts of DERs could exceed the thermal rating of substation equipment or it could exceed the available integration capacity at the circuit level. This would result in the need for a distribution planner to propose system modifications (or grid investments) to maintain proper equipment loading and distribution system operability. The costs for system modifications required to integrate DERs will need to be accounted for as part the LNBM described in Section C of this chapter.

The DER growth scenarios and their allocations, down to the circuit level, may be useful in providing an understanding of the potential for DERs to drive system upgrades. There is a range of issues that may arise depending on whether DERs are distributed evenly across the distribution

[123] A.13-11-003, SCE's 2015 GRC SCE-03, Vol. 4, p. 102.

circuits or clustered in a location on the distribution system. For example, if DERs are clustered at the end of a distribution circuit then it is more likely the distribution circuit will observe thermal, voltage, or protection concerns. If DERs are distributed evenly, then it is less likely significant issues will be triggered in most parts of the SCE Distribution System. While an even distribution of DERs throughout the territory and across distribution circuits would likely drive fewer issues, there is no assurance that customers or third parties would propose even distribution of DER projects across SCE's Distribution System. Clustered or large installations would have greater impacts on distribution facilities such as substations and circuits. For instance, if the DER growth was clustered in a region of the territory, those distribution facilities would likely experience problems such as overloads. Avoiding the clustering of DERs within an area is important to limiting the impacts to distribution facilities. As discussed in Chapter 2 Section B.5.a, the findings from SCE's ICA performed on the representative distribution circuits illustrated significantly less hosting capacity on lower voltage systems (*e.g.,* 4 kV) than higher voltage systems (*e.g.,* 12 kV, 16 kV). Given that the hosting capacity decreases as the electrical distance from the substation increases, there are even greater challenges associated with clustered DER installations on these low voltage systems.

e) Impact on the Planning Process Drives the Need for New Planning Capabilities

With increasing levels of DER penetration throughout the system, distribution planners will require adequate information and systems to properly plan and support operation of the distribution system. More sophisticated planning processes are needed to assess the current level of DER penetration, incorporate future DER forecasts, and evaluate the ability for DERs to meet forecasted system needs. Enhanced monitoring capabilities are required to adequately assess current levels of DERs and to evaluate their effectiveness. This will allow SCE to understand and distinguish between production and consumption on the distribution system. Increased penetration of DERs can lead to impacts on distribution facilities including equipment overloads or overvoltage conditions. Installation of additional devices that monitor power flow will provide valuable information to planners to support operating circuitry within the appropriate limits, and to better assess the impacts from circuit reconfigurations. Increased monitoring capabilities can also help to provide an assessment of DER effectiveness that can be used to support preparing future forecasts on the distribution system.

As DER penetration levels continue to rise, it will be necessary to accurately predict the impacts of DERs on long term forecasts in order to sufficiently develop a comprehensive picture of future system needs. Incorporating DERs into long term forecasting requires a thorough examination of DER profiles throughout the year in order to understand the impacts during peak and off-peak conditions and a change in the planning process as set forth in Chapter 6.[124] A tool that combines statistical analytics and data regression is necessary to facilitate this analysis. This new long term planning tool will enable system planners to more adequately predict long term system needs by taking into account DERs and their impacts on the distribution grid. It will also allow system planners to evaluate new ways to address long term needs such as considering the ability for DERs to meet those needs. These investments will assist SCE in having the right information (via monitoring) to plan the system, and the right tools to predict or forecast future needs that may be solved by traditional grid investments or DERs.

E. Demonstration and Deployment

1. Overview of Demonstration and Deployment Projects

The demonstration and deployment projects seek to validate the methodologies developed within the DRP and show how a modern grid can better enable DERs. At a high-level, the demonstration projects aim to show: (1) how the ICA methodology can be expanded to all circuits (including each line section) within an area and the anticipated impacts due to various scenarios; (2) how the LNBM developed in this DRP can be performed; (3) how DERs services could result in net benefits ; (4) how distribution operations, planning, and investment would be supported or

[124] Ch. 6, Overcoming Barriers to Deployment of DERS, Section D, Subsection3.

impacted at high levels of DER penetration; and (5) how the utility would serve as a distribution system operator of a microgrid where DERs support customer load and reliability services.

The demonstration projects will provide valuable information regarding how SCE should evolve the distribution planning process and invest in future grid technology to enable increased penetration of DERs. By relying on technology that is supported by SCE's proposed grid modernization efforts, these projects are aimed at improving the ability of DERs to provide customers with choices in how they generate and consume electricity while providing grid benefits and the appropriate level of operational awareness needed to reliably operate the 21st century power system. These projects will also investigate potential changes to internal business processes and refinements to methodologies developed as part of the DRP process. The demonstration projects are intended to help SCE overcome barriers related to DER integration and advance SCE's goal to provide an integrating platform for DERs. These demonstrations also play an important role in moving today's grid toward a grid that can handle "two-way flows of power" and will help shape future DRPs. SCE believes that these demonstrations will inform the utility, the Commission, the DER community, and the public of the future capabilities of the distribution system and inform stakeholders as they contemplate future capabilities of the system.

The Final Guidance directs the IOUs to propose five DER-focused demonstration and deployment projects. The first project is to apply the Commission-approved ICA methodology to all line sections or nodes within a Distribution Planning Area (DPA) (Demonstration A). The second project is to apply the LNBM in one DPA and evaluate, at a minimum, two infrastructure projects for possible deferral (Demonstration B). The third project is to demonstrate how DERs' services could result in net benefits (Demonstration C). Finally, the fourth and fifth projects (Demonstration D and E) demonstrate how distribution operations, planning, and investment would work at high levels of DER penetration, and how the utility would serve as a distribution system operator of a microgrid where DERs serve a significant portion of load and reliability services. To meet these requirements, SCE has divided the remainder of this section into three subsections:

- Section 2 provides an overview of the area that will be used throughout the demonstrations to meet the proposed objectives.
- Section 3 provides an overview of all of SCE's demonstration projects.
    - Section (a) provides an overview of a demonstration project that performs a study of the Dynamic Integration Capacity Analysis (Demonstration A or ICA Demonstration).
    - Section (b) provides an overview of a demonstration project that uses the Locational Net Benefits Methodology for one DPA and evaluates two grid projects for deferral (Demonstration B or LNBM Demonstration).
    - Section (c) provides an overview of a demonstration project that validates the use of DERs in the field to provide services associated with the DER avoided cost categories (Demonstration C or LNBM Field Demonstration).
    - Section (d) provides an overview of a demonstration project that assesses the operation of DERs at high penetration levels involving multiple circuits (Demonstration D or High DER Demonstration).
    - Section (e) provides an overview of a demonstration project, where the SCE serves as a distribution system operator of a microgrid (Demonstration E or Microgrid Demonstration).
- Section 4 discusses the need for cost recovery for DERs acquired as part of the demonstration projects.

SCE has also provided the detailed specifications for each project in Appendix D.

2. Demonstration and Deployment Project Area

Demonstration and deployment projects A through D will be studied or executed within the Orange County area of SCE's service territory because it is an area with ongoing activities to modernize the grid and integrate DERs. For the Demonstrations C and D, SCE will leverage two ongoing projects, its Preferred Resources Pilot (PRP) described in Section 2(a), below, and the Integrated Grid Project (IGP) described in Section 2(b). The IGP is a project geographically located within the boundaries of the PRP (PRP began in November 2013, while the IGP began in January 2014). For these demonstrations, SCE will leverage DER acquisition from SCE's demand side management programs, which target residential and business customer DER installations. SCE will also rely on competitive solicitations (*e.g.,* Local Capacity Requirements Request for Offers (RFO)). Additionally, obtaining input from stakeholders will be a critical component to the success of the demonstration projects.[125] SCE anticipates that leveraging the acquisition and stakeholder engagement activities from the PRP and IGP will assist the demonstration projects and support the Commission's objectives to inform the distribution planning process, make recommendations for future phases of the DRP, provide lessons learned, and begin transforming the power system.

SCE is also leveraging several other on-going efforts that may incorporate a microgrid to support optimization of resources in an area and to improve reliability. Any of these efforts will provide various opportunities to learn about microgrids and may be used to support the Microgrid Demonstration. One component of the Microgrid Demonstration project is to identify the location of the Microgrid Demonstration. While the physical location of this Microgrid Demonstration project could be outside of the PRP area, the specifications, located in Appendix D, would still apply to the selected project.[126]

a) Primary Deployment Project Area

SCE plans to use the PRP region for the Demonstrations A through D. The PRP was launched in 2013 to address a transmission-constrained area served by two "A" level substations[127] (*i.e.,* Johanna and Santiago substations). SCE serves approximately 250,000 customers in this region with the expected load growth of about three percent per year out past

[125] For example, as part of the PRP, SCE has engaged stakeholders via webinars and workshops to solicit input on barriers and solutions to DER implementation challenges. Similar engagement activities will be used to support the demonstration projects.

[126] Notwithstanding the selection of this demonstration's physical location, SCE plans to commence the project no later than one-year after Commission approval of the DRP.

[127] An "A" level substation (or A-station) is a substation that provides power to multiple distribution circuits via SCE's subtransmission system.

2022. This region is directly affected by the closure of the San Onofre Nuclear Generating Station (SONGS) and will also be affected should the nearby ocean-cooled power plants close in 2020 as part of California's once-through cooling policy.

SCE is targeting this region to obtain the resources necessary to conduct the demonstration projects. As part of the PRP, SCE has designed a portfolio of preferred resources (*i.e.,* mix of energy efficiency, demand response, renewable distributed generation, and energy storage) that could offset the expected load growth and is implementing an acquisition strategy to obtain preferred resources for this region. SCE is also developing a framework and process to measure the performance capabilities of preferred resources in offsetting the impact of the local electrical load growth.

SCE already has a request for offers in the area to attract renewable generation for the demonstration projects. However, the distribution system in the PRP area that will be used for the demonstration projects may not support a high level of DER penetration at the "B" Bank level. Accordingly, as part of the Demonstrations C and D, SCE is proposing to study and, if appropriate and necessary, make system upgrades to support the demonstration projects.[128]

b) Integrated Grid Project

For Demonstration D, the High DER Demonstration project, SCE will leverage the Integrated Grid Project, which is located within the PRP region at a "B" level substation[129] (Johanna Jr.).

128 SCE is seeking to fund the system upgrades, if needed, and to record the costs associated with these upgrades into the memo account that is discussed in Chapter 7. Please see Section E.4 of this chapter for further discussion regarding SCE's cost recovery proposal.

129 A "B" level substation (or B-station) is a distribution substation that provides power to multiple distribution circuits.

Figure II-11
The PRP and IGP Project Areas

The IGP is an integration project leveraging resources and activities from other SCE projects like the resource acquisition associated with the PRP. The work in the IGP is part of SCE's Electric Program Investment Charge (EPIC) Investment Plans.[130] The EPIC Program is administered by the IOUs and the California Energy Commission (CEC), although each IOU is limited to administering technology demonstration and deployments (or large scale pilots).[131] The IOUs developed, and the CPUC approved, a joint investment planning framework, which is divided into four funding categories:

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130 Final Guidance, p. 6 (stating that demonstration projects should, where feasible, be "coordinated with on-going efforts associated with SCE's smart grid deployment plan and EPIC investment plan.").

131 D.12-05-037, Finding of Fact No. 4, p. 90, ("For purposes of the EPIC program, technology demonstration and deployment as the installation and operation of pre-commercial technologies or strategies at a scale sufficiently large and in conditions sufficiently reflective of anticipated operating environments to enable appraisal of the operational and performance characteristics and the financial risks.").

(1) Renewable and Distributed Energy Resources Integration;

(2) Grid Modernization and Optimization;

(3) Customer-Focused Products and Services Enablement and Integration; and

(4) Cross-Cutting/Foundational Strategies and Technologies.[132]

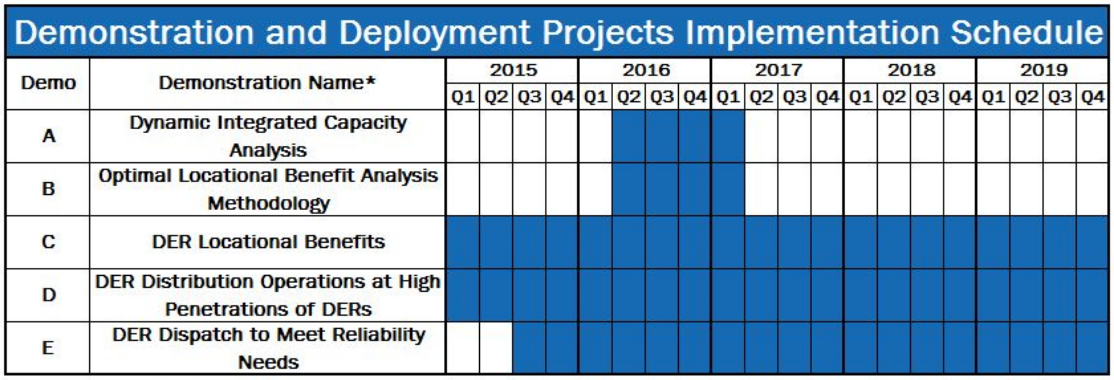
IGP is intended to optimize the use of DERs as well as analyze the impacts of high penetrations of DERs on the distribution system. The project will test advanced automation, enhanced communication networks, and grid-management control systems to enable the integration of DERs in a concentrated area on a limited number of distribution circuits. This analysis will focus on the effects of introducing emerging and innovative technology into the utility that co-optimizes consumer DERs with grid operations and utility assets. The IGP area has predominantly commercial and industrial customers and therefore the IGP will work to maximize both demand resource opportunities and the customer's ability to generate power with self-owned and operated renewable energy sources, but connected to the grid for reliability and stability operational reasons. The emerging technologies used in IGP are being funded from the 2012-2014 and the 2015-2017 Investment Plans approved by the Commission.[133]

Although both the PRP and IGP are intended to illustrate a variety of topics that go beyond the scope of SCE's five DRP demonstration and deployment projects, SCE will leverage the equipment and resources installed as part of the PRP and IGP to also accomplish at least four of the five demonstration projects. This is intended to create efficiencies and facilitate the timely commencement and completion of the demonstrations.

[132] *See* A.14-05-005 Amendment to Application of Southern California Edison Company for Approval of its 2015-2017 Triennial Investment Plan for the Electric Program Investment Charge (May 8, 2014), p. 3. *See also* D.15-04-020, Ordering Paragraph 1 at 61 (approving SCE's investment plan, as modified).

[133] D.13-11-025; D.15-04-020.

Figure II-12
High-Level Implementation Schedule[134]



*As noted within the Final Guidance

3. Demonstration and Deployment Projects A, B, C, D and E

a) Demonstration A: Demonstrate Dynamic Integration Capacity Analysis

The ICA Demonstration will utilize dynamic modeling techniques through power system modeling software to demonstrate dynamic integration capacity analysis in one DPA. SCE intends to use an area served by an "A" level substation within the Orange County area as the DPA. This area consists of multiple distribution substations with multiple distribution circuits (or feeders). SCE will utilize power system modeling software (*e.g.,* CYME, PSLF) to model the effects of DERs on the electrical distribution system under a few different scenarios. The software will allow SCE to determine hosting capacity, using dynamic modeling methods for every distribution circuit (and its respective line sections) within the various distribution substations. The software will also be used to assess the impact of DERs to the electrical grid under two scenarios required by the Final Guidance. For Scenario 1, the DERs do not cause power to flow beyond the substation busbar. For Scenario 2, the DERs technical maximum capacity is considered irrespective of power flow toward the transmission system.

[134] This timeline assumes that Commission approval of SCE's DRP occurs in March 2016 as contemplated within the DRP OIR.

The Final Guidance provides that this demonstration project must commence not later than six months after Commission approval of SCE's DRP. SCE plans to commence the project within one month after approval. The deliverable for this demonstration project is a report that will be submitted to the Commission. SCE plans to submit a final report approximately 12 months after Commission approval of the DRP. This report will communicate findings from the assessment of the two scenarios, identify lessons learned, and discuss recommendations on how these results can be used to improve SCE's ICA. Detailed specifications for Demonstration A are provided in Appendix D.

b) Demonstration B: Demonstrate the Optimal Location Benefit Analysis Methodology

The LNBM Demonstration will be a study that performs the Commission-approved locational net benefits methodology.[135] SCE will identify two distribution infrastructure projects within the PRP region for this demonstration. This demonstration will evaluate one near term distribution infrastructure project (less than 3-year lead time) and one longer term distribution infrastructure project (3 or more year lead time). SCE will calculate the deferral value[136] of the two infrastructure projects to determine "avoided cost" values. SCE will then develop a sample of DER portfolios that could potentially meet the criteria needed to defer the two projects. These DER portfolios will be valued using the appropriate elements of the LNBM.[137]

The Final Guidance states that this demonstration project must commence not later than one year after Commission approval of SCE's DRP. SCE plans to commence the project within 1 month after approval. The deliverable of this demonstration project is a report that will be

135 SCE understands "optimal location benefit analysis methodology" to be synonymous with the "locational net benefits methodology."

136 In Section C.3.e of this chapter, SCE recommended a methodology to value avoided cost for DERs using the Real Economic Carrying Charge (RECC) as one of the value components in LNBM

137 Note that the LNBM methodology will involve avoided costs, but may also include generation energy price forecasts, T&D losses, and other components, described in Section C of this chapter, above. The LNBM represents the net present value of future benefits minus future costs.

submitted to the Commission approximately 12 months after Commission approval of the DRP. This report will communicate the results of the comparison, identify lessons learned, and recommend ways to refine the LNBM. Detailed specifications for Demonstration B are provided in Appendix D.

c) Demonstration C: Demonstrate DER Locational Benefits

As previously indicated, SCE will seek to demonstrate DER Locational Benefits in the field, within the PRP's target region. As part of this LNBM Field Demonstration, SCE will leverage the PRP's portfolio assessment and acquisition plan to acquire DERs in a timely manner in order to conduct field demonstrations to test the ability of DERs to achieve net benefits consistent with the LNBM.

The goal of the LNBM Field Demonstration is to analyze how potential LNBM benefits can be validated in the field to meet the intended grid needs. This will demonstrate the ability of a portfolio of DERs to be integrated into both utility planning and operations and support achievement of state policy objectives. This effort will include studying, analyzing, and confirming whether DERs can function in an integrated manner to meet future local capacity requirements and energy needs. The project will also provide information on the cost to meet customer energy needs.

In the demonstration project, SCE will identify the optimal location(s) within the PRP region where at least three DER avoided cost categories or services could validate the ability of DERs to achieve net benefits consistent with the Optimal Location Benefit Analysis (*i.e.*, LNBM). Subsequently, SCE will develop a DER portfolio[138] and, as DERs are acquired and deployed, SCE will operate the DERs in concert to evaluate DERs' ability to achieve net benefits. Finally, SCE will evaluate and analyze results to validate DERs' ability to achieve optimal locational benefits.

[138] The demonstration will also explain how this DER portfolio was constructed "using locational factors such as load characteristics, customer mix, building characteristics and the like." Final Guidance, at p. 6.

To ensure the PRP meets the objectives of this demonstration, SCE will study the DER resources needed to accommodate this demonstration and their impacts on the grid to determine if and what kind of system upgrades may be necessary to support the LNBM Field Demonstration.

To ensure that DERs intended to support the LNBM Field Demonstration are deployed within the demonstration area, SCE will acquire DERs. This acquisition will support both the PRP and this demonstration project, and acquisition will occur via SCE's existing demand side management (DSM) programs and competitive solicitations. If needed, SCE will file separate cost recovery applications for DER procurement costs.

Demonstration C will commence no later than one year after Commission approval of the DRP. At this time, SCE has started aspects of this project in the form of acquisition, deployment and some testing, and will modify any necessary components based on a Commission decision regarding this proposed demonstration. The deliverable of this demonstration project is a report communicating the findings and recommendations to inform future iterations of the LNBM and to provide other recommendations that could support operation of the system during the conditions studied. SCE expects to complete this demonstration project approximately 3 years after Commission approval of the DRP. Detailed specifications for Demonstration C are provided in Appendix D.

d) Demonstration D: Demonstrate Distribution Operations at High Penetrations of DERS

The High DER Demonstration will leverage the existing IGP activities that include technology demonstration and deployment funded out of SCE's EPIC investment plan. The area selected for this demonstration project is the IGP project area or Johanna Jr. substation, as shown in Figure II-11. SCE anticipates integrating higher levels of DERs in the area as part of the fulfillment of proposals through the Local Capacity Requirements solicitation conducted by SCE in 2014.[139]

[139] https://www.sce.com/wps/portal/home/procurement/solicitation/lcr.

Additional DERs are being solicited as part of the PRP activities, including the PRP Distributed Generation Request for Offer.[140] As part of this demonstration, SCE will describe how the DER portfolios were constructed.

The above-mentioned efforts to acquire DER will support increased penetration in the area, and support a demonstration that seeks to validate potential grid benefits (*e.g.,* distribution deferral) that can be realized. The results of this demonstration will be helpful in understanding how SCE can take higher levels of DER penetration into consideration within distribution planning, and to provide an understanding of how increased penetration may impact the need for traditional grid investments. The knowledge learned from this demonstration may provide a prototype, or additional learning that can be applied territory wide. In addition, higher levels of penetration will allow SCE to test its current operational capabilities and those capabilities that are needed to coordinate third-party DER and potentially utility-owned DER. The technology infrastructure *(e.g.,* telecommunications, monitoring devices, and control systems) to be deployed in the area is aimed at providing additional capabilities (*e.g.,* monitoring, controls) that may enable coordination of higher levels of penetration throughout the SCE system.

The demonstration will serve as a test bed for emerging technologies leveraging several EPIC projects that have been previously approved by the Commission in SCE's two EPIC investment plans.[141] This test bed will consist of telecommunication and control systems to forecast, monitor, and control DERs and to facilitate higher levels of DER penetration. The demonstration will include modeling analysis of up to 5 of the 11 distribution circuits out of Johanna Jr. substation. The field demonstration will operate multiple DER devices in concert on one or multiple circuits; some of the DERs will be owned by SCE and others owned by customers and/or third party aggregators.

Pursuant to the Final Guidance, this demonstration project shall commence no later than one year after Commission approval of the DRP. At this time, SCE has started aspects of this

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140 https://www.sce.com/wps/portal/home/procurement/solicitation/prp-rfo/.

141 https://www.sce.com/wps/portal/home/regulatory/epic/.

project (*e.g.,* use case development, business requirements, architecture and design, and preliminary equipment procurement plans) and will, within one year after Commission approval of SCE's DRP, modify any necessary components based on the Commission approval. The deliverable of this demonstration project is an update report as part of future DRP filings, and as a final report at the completion of the project. These reports will summarize key successes and challenges relating to utilization of high DER penetration to provide potential grid benefits (e.g., project deferral), the planning and operational coordination of multiple DERs under high penetration, and effectiveness of solutions tested to support high penetration of DERs. Detailed specifications for Demonstration D are provided in Appendix D.

e) Demonstration E: Demonstrate DER Dispatch to Meet Reliability Needs

The Microgrid Demonstration seeks to provide additional customer value in the area of reliability, and has the potential for replication throughout the SCE service territory to a variety of customers. Serving as a distribution system operator, SCE will use a microgrid, in conjunction with DERs, to support customer load within Orange County. SCE believes it is important to advance a microgrid demonstration in a way that meets the goals of the Demonstration Project while providing value to its customers. To that end, SCE is currently in discussion with multiple customers (*e.g.,* military facilities, campuses) to engage their interest in participation in a microgrid project and to obtain a firm commitment. If a commitment cannot be obtained in the Orange County area, SCE will leverage a location with existing resources (*e.g.,* equipment, DER) in another part of SCE's service territory that has potential for expansion to support the demonstration of a microgrid.

The project will demonstrate multiple DERs dispatched in a coordinated manner using one or more dedicated control systems to maintain grid reliability and optimize operations. The project will describe how the portfolio of third party and utility-owned DERs were constructed, dispatched, and managed. This demonstration will also define operational functionalities necessary to support situational awareness, coordination of DERs, and reliability services to be achieved.

This demonstration project will commence not later than one year after Commission approval of SCE's DRP. While SCE is still in discussion with multiple customers to gauge their interest, SCE is structuring and timing these discussions to commence the project within one year after approval of this DRP. This timing will also allow SCE to obtain a full understanding of the ruling requirements and the concept of a Utility as a distribution system operator managing a microgrid. The deliverables of this demonstration project are an update report as part of future DRP filings and a final report at the completion of the project. These reports will summarize key successes and challenges relating to the utility as distribution system operator managing a microgrid and the overall effectiveness of solutions tested within the demonstration. Detailed specifications for Demonstration E are provided in Appendix D.

4. Cost Recovery for the Demonstration and Deployment Projects

The Final Guidance provides that utilities "shall include any expected cost recovery for these demonstration projects as part of their DRP Applications, including any specific proposals related to minimum cost thresholds requiring Commission approval."[142] Regarding Demonstrations C and D, SCE does not know at this time if and what kind of system upgrades may be required to support either project. As such, SCE will conduct an evaluation (including an assessment of any generation impacts) of any distribution system upgrades that may be necessary to support either Demonstration Project and assure that DERs are available to meet the demonstration specifications and goals. Similarly, for Demonstration E, SCE does not know at this time if and what kind of funding may be required to support the project.[143] Accordingly, SCE is proposing that it will record the revenue requirement associated with incremental costs for Demonstrations C, D, and E into a Distributed Energy Resources Memorandum Account (as discussed in Chapter 7, Section C), if and as needed.[144]

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[142] Final Guidance, p. 6.

[143] Examples of related microgrid costs may include installation of substation automation, communications hardware, controls, and switching and protection related equipment.

[144] Establishing the DERMA will allow SCE the opportunity to recover the incremental revenue requirement associated with these new and unanticipated capital expenditures if they exceed levels authorized in SCE's test year 2015 GRC. This review would take place in SCE's test year 2018 GRC.

Further, regarding any cost recovery for costs associated with the DERs acquired for the field demonstration projects, SCE believes such cost recovery should adhere to the principle that, since the demonstration projects provide benefits to the entire distribution system, all of the utility's distribution customers should be responsible for paying the costs. As discussed above and explained in the Final Guidance, the DER demonstration resources are being acquired to demonstrate that future distribution investments that would otherwise be required to be made to SCE's distribution system can be deferred or avoided due to DER deployment. Therefore, the DER acquisition costs associated with the field demonstration projects should be recovered through distribution rates and paid for by all customers because the DER demonstration projects provide benefits to SCE's distribution system.[145]

[145] To ensure that DERs intended to support the Demonstrations C and D are deployed within the demonstration area, SCE will acquire DERs. This acquisition will support both the PRP and this demonstration project, and acquisition will occur via SCE's existing demand side management (DSM) programs and competitive solicitations. If needed, SCE will file separate cost recovery applications for DER procurement costs.

III.

CHAPTER 3: DATA ACCESS

A. Introduction and Executive Summary

As greater numbers of DERs are interconnected to the grid and as the telecommunications technologies advance, an increasingly greater volume of data will become available to the utilities, the Commission, and others. This data can be valuable in supporting real-time grid operations, forecasting and planning, and encouraging the appropriate siting and development of DERs. SCE's policy proposal for data sharing among IOUs and DER providers, as set forth in this volume, focuses on facilitating data sharing to encourage the development of DERs and customer choices to support grid reliability and modernization, while maintaining appropriate controls to protect customer privacy and confidential information.

The Final Guidance requires SCE to propose a policy for what kind of data can and should be shared, subject to existing legal and regulatory requirements, and a process for sharing this data with customers and DER owners and operators. SCE's proposed policy aims to provide relevant data to customers and DER providers who wish to expand DER deployment. Where SCE believes it is prohibited from sharing data due to confidentiality, privacy, or security limitations, the Final Guidance asks that SCE explain why data cannot be shared and propose alternatives for supporting DRP goals.[146]

With these goals in mind, SCE's proposed data access policy regarding the data types in the Final Guidance is provided in Section B of this chapter and in Appendix G. In particular, SCE analyzed the specific data types listed in the Final Guidance and identified: (i) the data types that SCE already provides publicly, including where SCE makes the data available; (ii) data types that SCE can begin providing, considering SCE's guiding principles for data sharing; and (iii) data types

[146] Final Guidance, p. 8.

that merit further consideration in a stakeholder workshop process to determine the most cost-effective and useful way to share the data under SCE's guiding principles.

The Final Guidance requires that SCE develop a plan for how it can leverage DER owner/operator data.[147] In Section C, SCE describes third party data that would benefit grid planning and operations and proposes a methodology for sharing that data.

Section D describes a stakeholder workshop process that SCE proposes to further consider how utilities can share data with third parties and vice versa. Issues to be considered at the workshop include defining third party data needs, identifying efficient methods for providing the data, developing aggregation and anonymization techniques where necessary, developing a process in which third parties can share data with utilities, and improving/adding to SCE's data access tools.

Finally, per the Final Guidance, SCE describes in Section E its current plans for obtaining data (beyond interval billing data) from smart meters.

B. SCE's Data Access Policy

1. Guiding Principles

SCE supports sharing data with customers and third party DER owners and operators to facilitate DER integration. SCE believes that data should be shared when:

- Doing so would not violate existing Commission rules, state or federal laws, regulations or any other applicable requirements protecting customer privacy, trade secrets, proprietary information, grid reliability and security, or public safety, including the laws and rules in Appendix F;
- Parties have identified a purpose for the particular granularity of data requested such that the manner in which access to the data is granted is narrowly tailored to meet Commission-specified needs;[148]

[147] Final Guidance, p. 9.

- The data is already collected by SCE in the appropriate form or could be collected in such form without unreasonable costs or effort as weighed against the identified benefits of the data, as determined by the Commission;
- The Commission has decided the need for, the appropriateness of, and the methodology for sharing any data that may be market-sensitive or may be used to manipulate markets.

2. SCE's Policy for Sharing Data Types Identified in the Final Guidance

a) Data Types Available Through DRP Process

SCE is already making many types of data identified in the Final Guidance available publicly through this DRP process. SCE is on a path to expand currently available data even in advance of the DRP order. As described in Chapter 2, SCE's Distributed Energy Resource Interconnection Map (DERiM) will expand the data available to its customers and developers through SCE's Renewable Auction Mechanism (RAM) maps in a more user-friendly manner. SCE's DERiM contains distribution circuitry information, such as distribution feeder names and topology, as well as circuit-to-substation relationships. In terms of data types, the DERiM provides three data types required in the Final Guidance: (1) non-coincident peak load forecast information at the circuit and substation level; (2) capacity at the circuit level; and (3) existing distributed generation population characteristics. In addition to these data types identified in the Final Guidance, the DERiM will also provide current penetration levels (*i.e.*, the ratio of generating resources to peak load), projected load, and the results of the Integration Capacity Analysis (ICA)[149] that will be useful for customers and developers to identify locations to interconnect DERs with the best distribution grid impacts and associated interconnection upgrade costs.

Continued from the previous page
148 SCE proposes a workshop process in this Chapter in which parties and the Commission may discuss and determine how the use of data supports promoting the goals of the DRP.

149 Chapter 2, Section B.

The DERiM is user-friendly by allowing mobile access, providing a variety of basemap options, supporting user-defined data filtering, providing filtering functionality and allowing users to export information from the maps, store the content locally on the user's electronic device, and access information when offline. In addition, the DERiM utilizes active database connections to present users with the most up-to-date data. SCE proposes to discuss the DERiM at stakeholder workshops, as explained below, to incorporate feedback on additional data types and functionality that may be included to enhance the usability and value to customers and third parties.

In addition, data types identified in the Final Guidance, such as other customer DER adoption forecasts, and distribution planning load forecast, based on forecasting scenarios proposed elsewhere in the plan, are being provided in SCE's DRP.[150] Appendix G provides more details on the data identified in the Final Guidance that will be available to third parties on DERiM or is being provided through SCE's DRP.

b) Data Types Currently Publicly Available Similar to Data Types Identified in the Final Guidance

SCE currently provides other data types, albeit at a different level of aggregation or in a slightly different format than identified in the Final Guidance. For example, the Final Guidance identifies outage data at the substation and feeder level. SCE provides outage data via its system reliability reports – System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI) – by county, city, and circuit on SCE.com.[151]

Likewise, the Final Guidance identifies SCE's substation and feeder-level projected investment needs over a ten-year period. SCE includes projected investment needs by substation and feeder level in its triennial general rate case. SCE's investment plans are updated for each general rate case, in which SCE demonstrates the need for, and reasonableness of, distribution

[150] Chapter 2, Section D.

[151] *See:* https://www.sce.com/wps/portal/home/outage-center/reliability-reports.

projects. Such existing publicly available data sources should first be considered and analyzed to understand whether this meets the data needs of third parties.

To the extent the Commission and third parties need existing, publicly available data at a different level of granularity or in a different form, SCE proposes to discuss how to provide this data via a stakeholder process described in Section D. Appendix G provides additional information on the data currently being provided publicly and the location where third parties may access the data.

c) Data Types That Are Currently Non-Public That Will Be Made Available, If Needed by Third Parties

SCE analyzed the data types identified in the Final Guidance and determined that several data elements are not currently provided publicly but can be shared with adequate aggregation or anonymization, where appropriate, to protect confidentiality and grid security. For example, SCE currently provides its distributed generation (DG) adoption forecasts for the CEC's Integrated Energy Policy Report (IEPR). This forecast could be provided publicly on SCE.com. Other data types, such as coincident peak, backup generator population, and generation production characteristics for intermittent resources, may, depending on the level of granularity, contain customer-confidential information or may be "reverse-engineered" to identify individual customers.

For these types of data, SCE proposes a stakeholder workshop process that would ultimately result in the submission of a joint proposal for Commission approval that would specifically define how and which third parties receive what types of data for which purpose(s). The workshops would provide parties with the opportunity to determine the need for different types of data, the level of granularity needed and why, the data format and the process for data transmission. This workshop process would be particularly useful to the extent it explores aggregation/anonymization techniques that mitigate customer-confidentiality and grid security concerns, because the

Commission has not yet approved aggregation methods for data other than interval usage data,[152] and the workshops would provide an open and collaborative forum for resolving this issue.

The data elements that SCE has identified that will be provided publicly, if third parties need the data, along with additional information on considerations and potential topics for workshops, are provided in Appendix G.

d) Data Types That Should Be Considered for Data Sharing in a Workshop

To the extent the data SCE already offers publicly, makes public through this filing, or plans to offer publicly in accordance with the previous sections is insufficient to meet the needs of DER providers, SCE recommends convening workshops to determine how any gaps could be addressed and whether certain data types should be provided publicly. For example, it is unclear what value DER developers would receive from utility-provided household income levels for CARE customers, one data type identified in the Final Guidance. There may be more appropriate venues for obtaining that information, if needed; for instance, census data includes household income levels. It is appropriate to understand why the data is needed and how it can be obtained in a least-cost manner.

Sharing other data types, in particular data from sensor systems, Supervisory Control and Data Acquisition (SCADA) systems, and substation automation systems, raises customer confidentiality and physical security concerns. From a practical perspective, the sheer volume of operational data associated with these systems, which may include data such as the real-time status of SCE's facilities, may be of minimal use to third parties. Also, without the proper context regarding grid conditions, the data may be misinterpreted. For example, temporary abnormal grid conditions, such as outages or weather conditions, may temporarily affect the data.

[152] The Commission addressed aggregation/anonymization of interval usage data in the Smart Grid Rulemaking, R.08-12-009, Phase 3, which culminated in the issuance of D.14-05-016 adopting aggregation and anonymization rules for certain use cases.

SCE recognizes that operational data may be valuable to third parties, particularly data from days that represent a range of system conditions. SCE may be able to provide time-delayed data on an aggregated basis (*e.g.*, at the circuit segment level) for particular representative days. For example, SCE could provide data for days characterized by low customer use, low solar generation, peak use, peak solar generation, weekdays, weekend days, "heat storm" periods, low load/high solar sequences and other representative days that DER providers would find useful. This data could be provided for certain representative circuits, such as the 30 representative circuits SCE is currently using in the ICA and could be provided at the same as the ICA. This data may provide a valuable proxy for real-time operational data, avoiding many of the problems of publicizing SCE's operational data in real time.

SCE recommends that these types of data elements be considered at stakeholder workshops, with express consideration for what precise use third parties have for the data, at what level of granularity, and how SCE can provide the data in a meaningful, cost-effective manner without compromising customer privacy or raising physical security concerns. Additional information on these data types are included in Appendix G.

3. Process for Providing Data to Third Parties

a) Methods for Transferring Data

SCE proposes to leverage existing and planned systems and platforms to provide data to third parties. As described previously, SCE proposes to provide various distribution system data through its DERiM. In addition, SCE currently has several methods in place for third parties to request and receive access to customer usage data. The first is SCE's Customer Data Access (CDA) platform, which allows customer-authorized third parties to access interval usage data through the CDA platform utilizing the North American Energy Standards Board (NAESB) Energy Service Provider Interface (ESPI) standard. Commission Decision (D.)13-09-025 authorized SCE to build the CDA platform, and SCE's Rule 26 established the rules and processes by which third parties may access that interval usage data.[153]

The second method is SCE's Data Request and Release Process (DRRP), which facilitates the disclosure of certain types of data to eligible academic researchers, local government entities, and state and federal agencies under provisions of SCE's Rule 26 that differ from CDA data disclosure. The DRRP was established pursuant to D.14-05-016 and leverages the web portal established for SCE's CDA program.[154] In addition to processing data requests per D.14-05-016, SCE also posts anonymized and aggregated customer usage data on its website under the protocols adopted in that decision for quarterly web presentment.

Depending on the results of the workshop process adopted in connection with this proceeding, SCE could post additional data on SCE.com data on a recurring (quarterly or annual) basis, depending on the type of data. For example, SCE may only update its Customer DG adoption forecasts biennially as input to the CEC's IEPR. This periodic posting requirement would cut down on the number of individual requests being made through the data request process. For unique data needs, SCE proposes leveraging the CDA and DRRP processes, if appropriate.

b) Ability of Non-Market Participants to Access Market-Sensitive Information Through the DPRG Process

SCE's distribution planning and DER deployment analysis is likely to produce confidential, market-sensitive information. Releasing market-sensitive information to DER developers could severely harm SCE's ability to acquire DERs performing grid functions at the lowest possible cost to its customers. Such market sensitive information should therefore be kept confidential. At the same time, non-market participant parties have a legitimate interest in reviewing this information to ensure that SCE is appropriately applying the Commission-approved deferral framework that SCE believes should be developed, as discussed in Chapter 8(C)(1).

[153] D.13-09-025, Ordering Paragraph 12, p. 74.

[154] D.14-05-016, Ordering Paragraphs 1 and 3, pp. 156-157.

For such confidential or market-sensitive information, SCE proposes using a Distribution Planning Review Group (DPRG) process, as discussed in Chapter 2, which would mirror the Procurement Review Group process already used by the Commission in the power procurement context. This process would allow non-market participants that are willing to sign a standard non-disclosure agreement (NDA) to access market-sensitive, confidential information, while also ensuring that market-sensitive information is not improperly disclosed to market participants.

c) Ability to Access Data in Real-Time

The Final Guidance requires SCE to propose a "method for making this data available in as near real time as possible, subject to existing privacy constraints, with explicit consideration for how third parties can access this data directly, using the ESPI Customer Data Access system."[155] For most of the data types identified in the Final Guidance, such as data related to forecasts, aggregated customer information, and distribution planning data, SCE does not update the data in real-time, nor would there be any value in collecting or providing such data in real-time. For accessing data through DERiM, and/or accessing future data posted on SCE's Customer Data Access system, third parties could access data when even they want it, without the need to wait for a data request to be fulfilled.

Regarding SCADA data, which is collected in real-time, SCE proposes to discuss this data in workshops to evaluate the benefits of providing the data in real-time. Direct access to SCE's SCADA systems will not be provided due to the cyber security and physical grid security risks. These systems are used to control field devices and substation devices such as remote controlled switches, voltage regulating equipment, circuit breakers, and remote automatic reclosers. Allowing access to these systems would compromise the control of these devices which could cause outages that could harm customers, damage equipment and threaten the grid. In addition, as SCE discussed previously in this chapter, there are other issues associated with providing raw SCADA

[155] Final Guidance, p. 9.

data. Such issues could be mitigated through providing data for representative days and representative circuits; SCE proposes discussing this proposal in workshops. In these workshops, third party needs associated with this data can be determined, and parties can collaborate to propose enhancements to SCE's DERiM that could satisfy those data needs.

C. Data That SCE Should Receive from Third Parties

The Final Guidance also requires that each utility's data sharing policy include "[r]equirements for receiving data from DER owners (DER owners/operators)"[156] and that each utility's DRP include a plan for how it can "leverage DER owner/operator data."[157] The Final Guidance also requires that each utility's data sharing procedures include a "process for sharing market data from DER owners/operators with Utilities, including policies that deal with confidentiality."[158] This section discusses the data that SCE requires from DER operators related to distribution planning and grid operations and proposes methods for the transmission of the data from the DER operator to the utility.

1. Third Party Data Sharing and Data Uses for SCE

In this Section, SCE describes the data types that would be useful for SCE to receive from DER operators. In particular, data types including voltage, current, power factor, real and reactive power, and device status for various DERs would provide benefits for SCE's distribution planning and real-time operations. Table III-8 provides the data that would be beneficial for utilities to receive from DER operators.

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156 Final Guidance, p. 8.

157 Final Guidance, p. 9.

158 *Id.*

Table III-8
Beneficial DER Operator Data

Data Types	Granularity	Benefits to Utility
For Distribution Planning:		
Electric Vehicle Loads (including voltage, current, power factor, real and reactive power, and status)	Monthly, in 15-minute intervals	• Load/DER disaggregation analysis to separate EV load from traditional load (Residential ES can be misinterpreted as EVs without this data) • EV adoption forecasting by distribution feeder leveraging data trends • Validate locational value of EVs at specific connection point • Understand customer charging habits to leverage in future infrastructure upgrade designs
Generation from Photovoltaic Systems (including voltage, current, power factor, real and reactive power, and status)	Monthly, in 15-minute intervals	• Load/DER disaggregation analysis to separate PV output from load profile • Leverage actual PV performance in dependability analysis to defer/offset traditional infrastructure upgrades • Validate locational value of PV at specific connection point
Performance of Energy Storage Systems (including voltage, current, power factor, real and reactive power, and status)	Monthly, in 15-minute intervals	• Load/DER disaggregation analysis to separate ES output from load profile • Leverage actual ES performance in dependability analysis to defer/offset traditional infrastructure upgrades • Validate locational value of ES at specific connection point • Assess impacts of market performing ES to local distribution system
For Real-Time Grid Operations:		
Real-time data received through Rule 21 for the DERs described above	Real-time	• Informs decision making when temporary distribution reconfigurations are necessary • Situational awareness of DER status for utility construction, maintenance, and repair personnel including islanded operations • Leverage DERs for storm support (heat, wind, rain, snow) • Leverage DERs for voltage support (high/low) • More accurate load measurements

2. How SCE Will Leverage This Third-Party Data

a) Distribution Planning

SCE's distribution planning would benefit from increased data from DER operators. For example, it would be useful for SCE to know the location of DERs, the type of DERs, and the size of the project. Distribution planners can build this information into the distribution planning process, thereby maximizing the DER benefit to the grid. In addition, that knowledge would help SCE determine whether the DERs provide an alternative to or provide a way to better optimize traditional capital upgrades (*e.g.,* wires, transformers, capacitors). Finally, this type of data sharing will provide SCE improved integration of resources between transmission and distribution such as clear indication of where and when specific DERs may be leveraged for transmission reliability versus distribution reliability as the two are not always aligned.

b) Real-Time Grid Operations

In addition to distribution planning benefits, data from DER operators will improve SCE's ability to operate the grid. This includes optimizing capacity utilization by leveraging available DER capacity during peak demand periods or emergency conditions rather than overloading utility infrastructure or in worst case scenarios imposing temporary outages. Periods of low demand can be communicated to ES and PEVs waiting to charge. In addition, this information will help SCE to maintain proper voltage by enabling coordination between DERs and utility controlled, voltage regulating equipment. Without this coordination, there is potential that both assets can attempt to fix the same low voltage issue, resulting in a different high voltage issue. Operators can include DERs in determining which available resources can best resolve voltage concerns rather than working around them. Similar to distribution planning, having the information on the deployed DERs will maximize the benefits of DER output because operators can leverage DER resources during scheduling of planned outage scenarios. Examples could include scheduling certain maintenance and repair work during hours when affected ES devices would idle regardless based on historical output data or not calling on demand response resources because historical data indicates a risk for over usage. Finally, enhanced data sharing from DER operators to SCE will allow grid operators to identify potential safety issues stemming from malfunctioning or failed equipment and unintended islanded operations.

3. Data Transfer Methods from DER Operators to Utilities

For the data types needed for distribution planning purposes, SCE recommends that DER operators enter into user agreements (such as interconnection agreements or other tariffs), pursuant to which the operators are required to provide specific data elements in prescribed granularity and frequency. Potential methods for this data exchange could include dedicated broadband telemetry units for real time applications, or standardized format files submitted through an online portal for planning applications, depending on the data available from DER operators.

Today, data is collected through the telemetry requirements included in Rule 21 interconnections. Generators who interconnect and have projects greater than 1 MW must install telemetry to collect the required data. In the future, as the deployment of smaller-scale DER projects expand, the utilities, Commission, and other stakeholders should evaluate whether Rule 21 telemetry requirements should apply to these smaller projects. As an alternative to requiring telemetry for smaller-scale projects, parties could collaborate to determine alternative ways to provide the data required for real-time grid operations.

SCE anticipates that there will be numerous DER operators with varying levels of data collection sophistication and data availability. For this reason, SCE recommends that the method of data transfer from DER operators to utilities be a topic of discussion at the proposed stakeholder workshops described in the next section. The stakeholder workshop could also be leveraged to determine what would be included in user agreements and/or potential tariff updates, as well as technology/telemetry requirements, and other potential data transfer methods.

In addition, the Final Guidance requires SCE to propose a process for sharing market data from DER operators to utilities. SCE recommends that this type of data sharing be included in the workshop process proposed in the next section. This type of data sharing would require parties to discuss appropriate confidentiality issues depending on the type of data available from DER operators. Issues include whether a non-disclosure agreement is necessary, whether access to such data would be for grid operations personnel and not market-participant personnel, and if the information is non-sensitive and can be made public.

D. Stakeholder Workshop Process

This section describes SCE's proposal for stakeholder workshops to address access to data elements that are listed in the Final Guidance for which additional clarification is necessary. SCE recommends that the utilities, Commission staff, and other interested third parties engage in stakeholder workshops, modeled after those utilized in Phase 3 of the Smart Grid Proceeding that would ultimately lead to a joint proposal to be submitted to the Commission for approval.

In Phase 3 of the Smart Grid Rulemaking, the utilities, Commission staff, and interested parties held workshops to understand data needs from third parties, and also understand the applicable data privacy laws and rules. The goal of the stakeholder workshops in this case should include the following:

1. Define Data Needs

In future workshops, third parties should define precisely what data elements are needed. This should include the data element sought, the frequency that the data would need to be collected, and the granularity needed. This assessment process would assist in understanding what current rules and laws potentially apply to that data, and is also necessary to understand whether the utilities collect the data, or what alternatives could be provided. In addition, the parties could discuss the data needed by the utilities from DER operators to operate the future electric grid.

2. Identify Requestors and Purpose for Data Access

In Phase 3 of the Smart Grid proceeding, various parties submitted "use cases," stating who needed which data elements and for what purpose(s). As a result of this process, D.14-05-016 prescribed what types of customer-related data may be shared with specific third parties for specific purposes. In the vast majority of instances, customer-confidential data is not permitted to be disclosed to third parties without customer consent, but the stakeholder process identified methods of aggregating or anonymizing data to mitigate customer confidentiality concerns, where possible. In addition, D.14-05-016 adopted requirements for the eligibility verification of the third parties requesting certain types of data. SCE recommends employing a similar process here.

3. Identify Data Transfer Methods

SCE already provides myriad data on SCE.com. As discussed in Section B(2) and (3) above, SCE recommends leveraging SCE.com for providing additional data, where appropriate. In addition, the methods by which DER operators would transfer data to the utilities should also be fine-tuned. This should include consideration of (1) methods of transferring monthly data from DER operators to the utilities, (2) real-time telemetry requirements to promote effective grid operations, and (3) alternatives to telemetry for smaller-scale DERs.

4. Propose Aggregation and Anonymization Techniques

The Commission adopted aggregation techniques in the Direct Access Proceeding in D.97-10-031,[159] and adopted other aggregation/anonymization methods in D.14-05-016, which apply only to customer usage data for specific use cases. Therefore, aggregation and anonymization techniques for the data discussed in the Final Guidance may need to be developed. For example, SCE could use aggregation/anonymization protocols to provide useful data regarding backup generator populations while mitigating customer-confidentiality issues. SCE could potentially provide the number of such installations and characteristics of the installations by zip code or some other geographic filter, assuming the group is sufficiently large, to mitigate reverse-identification risks. However, to develop an effective protocol, SCE must first understand from third parties what they need and why.

5. Stakeholder Workshop Report

The end product of the stakeholder workshops should be a workshop report that summarizes the discussions and recommendations following the workshop. As in Phase 3 of the Smart Grid proceeding, the utilities could develop the workshop report and propose policies based on the workshops. All parties who participated in the workshops could then provide comments on

[159] Commonly referred to as the 15/15 Rule, this technique requires that any aggregated information provided by SCE must be made up of at least 15 customers and a single customer's load must be less than 15% of an assigned category. If the number of customers in the complied data is below 15, or if a single customer's load is more than 15% of the total data, categories must be combined before the information is released. The Rule further requires that if the 15/15 Rule is triggered for a second time after the data has been screened once already using the 15/15 Rule, the customer be dropped from the information provided.

the workshop report. The Commission could use the report and comments to adopt a final data access policy.

6. Commission Decision

SCE recommends that the stakeholder workshops be conducted and a workshop report be submitted by the end of 2015. This would allow enough time for Commission staff to include a final, statewide data access policy to be included in the Decision that addresses SCE's DRP Application. As it relates to data access, the Decision should include determinations on the following issues:

1. Definition of data to be provided (including granularity and frequency);
2. Define what third parties are eligible to receive what data;
3. Adopt aggregation and/or anonymization methods for data not addressed in previous Commission Decisions;
4. Adopt standard data transmission methods (e.g., posted to website, provided through CDA or DRRP);
5. Determine data access process from DER operators to utilities including telemetry requirements, use of user agreements, and/or tariff updates.

E. Accessing Smart Meter Data

This section describes SCE's plan to obtain data beyond interval billing data that reflect power quality and other factors. The Final Guidance requires SCE to describe its plan to specifically collect voltage, frequency, and reactive power/power factor data. This chapter describes the capability of SCE's Edison SmartConnect meters (Smart Meters) to access these data types and the associated technical considerations.

1. Edison SmartConnect Data Requirements

The following provides a summary list of the Commission's original requirements for a Smart Meter system:[160]

1. Implementation of price-responsive tariffs.
2. Collection of interval data that supports customer understanding of hourly usage patterns and relationship to costs.
3. Customer access to usage data with flexibility such that changes in access frequency do not result in additional costs.
4. Compatible with applications that provide education and energy management information, customized billing, and support improved complaint resolution.
5. Compatible with utility systems that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading, outage management, reduction of theft and diversion, improved forecasting, workforce management, etc.
6. Capable of interfacing with load control communication technology.

Smart Meters allow for the collection of interval usage data that enables price responsive tariffs, increases customers' understanding of their energy usage, and provides operational efficiencies for SCE and its customers, in compliance with Commission directives. Smart Meters were not specifically designed to collect data related to the elements described in the Final Guidance.

2. Technical Considerations and Data Availability

The Final Guidance requires the utilities to address sharing data collected from Smart Meters including voltage, frequency, and reactive power/power factor. Currently, the majority of

[160] *See* Rulemaking (R.)02-06-001, Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for the Advanced Metering Infrastructure Business Case Analysis, dated February 19, 2004.

SCE's Smart Meters collect voltage-related data including interval voltage data, hourly maximum and minimum voltage, and voltage-based meter events (*e.g.,* events where voltage exceeds a pre-configured voltage threshold). SCE has just begun to collect and store this data daily. SCE is piloting uses for the voltage data that includes an analytics tool to help (1) identify transformer overloading conditions, (2) determine whether a service transformer load is contributing to high or low voltage at the customer level, (3) compare voltage of customers connected to a transformer in case of power quality issues, and (4) evaluate capacitor bank placement requirements based on voltage deterioration. SCE's Smart Meters allow SCE to collect enormous volumes of voltage data from its customers. SCE recommends addressing voltage data collected by Smart Meters at the stakeholder workshop and to determine how to provide the data in the most cost-efficient manner.

SCE currently does not collect frequency and reactive power/power factor data. This is because the vast majority of SCE's Smart Meters do not have the capability to record this data due to hardware limitations.[161] Because the collection of the frequency and reactive power/power factor is not a software or firmware limitation, SCE would need to replace the Smart Meters to be able to collect this data. Therefore, it is not feasible for SCE to collect and share this data at this time.

161 Only a small percentage of SCE's smart meter population (used for large commercial customers only) have the technical capability to collect frequency and reactive power/power factor. However, the data is not currently collected.

Chapter 4:
Tariffs and Contracts

IV.

CHAPTER 4: TARIFFS AND CONTRACTS

A. Introduction and Executive Summary

The Commission stated that "the goal of [the DRP] is to begin the process of moving the IOUs towards a more full integration of DERs into their distribution system planning, operations and investment."[162] In compliance with the Final Guidance, this chapter: (1) summarizes "relevant existing tariffs that govern/incent DERs;" (2) provides "recommendations for how locational values could be integrated into [those] tariffs;" (3) recommends "new services, tariff structures or incentives" to support successful implementation of the demonstration projects in the DRP; and (4) recommends a process for identifying "refinements to interconnection policies that account for locational values."[163]

In Section B, SCE summarizes its existing tariffs that govern or provide incentives for DERs. In Section C, SCE recommends a process to determine how locational values could be integrated into the Commission's regulatory framework.[164] In Section D, SCE recommends ways to leverage existing services or incentives to support the timely

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162 DRP Ruling , p. 5.

163 Final Guidance, p. 9. Section 769(b)(2) of the Public Utilities Code requires the IOUs to "propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives," and "propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources." To meet this statutory requirement, the Commission issued the Final Guidance and directed the IOUs to provide: (1) "an outline of all relevant existing tariffs that govern/incent DERs," (2) recommendations for how locational values could be integrated into those existing tariffs for DERs, (3) "[r]ecommendations for new services, tariff structures or incentives for DERs that could be implemented as part of the demonstrations programs" proposed in the DRP Ruling and Final Guidance, and (4) "[r]ecommendations for further refinements to Interconnection policies that account for locational values."

164 SCE has some 565 tariffs, which SCE recognizes may ultimately be modified by the DRP decisions. Included in these tariffs is some 116 customer rate offerings. SCE does not envision the DRP modifying the customer rate tariffs, but rather the balance of the company tariffs that address design, interconnection rules, etc.

implementation of SCE's DRP demonstration projects, including enhancing its current customer program incentives. In Section E, SCE recommends a process for determining how locational values could be reflected in interconnection policies going forward.

B. Outline of SCE's Relevant Existing Tariffs That Currently Govern or Incent DERS

SCE's tariffs include rate schedules (*e.g.*, Schedule D – Domestic, which is the default rate applicable to the majority of SCE's residential customers, Schedule TOU-8, which is applicable to eligible large power commercial and industrial customers, and Schedule TOU-PA-2 which is applicable to small to medium power agricultural and pumping customers), rules (*e.g.,* Rule 21 – Generating Facility Interconnections, which governs how SCE interconnects generation to SCE's distribution system), filed forms, including standard contracts and forms reflecting customer authorization for data, and preliminary statements, which include various memorandum accounts and balancing accounts.[165] The tariffs (rate schedules and rules) described below are available today and govern, incent, or help advance the deployment of DERs, with the rate schedules providing the indicators for the incentive mechanisms.[166]

For example, the rate schedules applicable to Distributed Renewable Generating Facilities- incent customers to install and interconnect certain renewable generating facilities to SCE's system[167] to either offset their energy use in return for bill credits, or to sell power to SCE with such wholesale sales being made under either the auspices of the Public Utilities Regulatory Policies Act (PURPA) or their status as public power entities. The

[165] SCE's Tariff Books are available at https://www.sce.com/wps/portal/home/regulatory/tariff-books/!ut/p/b0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOINLdwdPTyDDTwtfAKNDTydnDz9zdxMjA28jfSDU_P0C7IdFQGGI783/.

[166] Except for certain conditions indicated in various rate schedules, the costs of the tariffs are covered by the general body of customers.

[167] Not all of the rate schedules listed are limited to distribution grid-interconnected resources; some are available to transmission-interconnected resources.

rate schedules applicable to Demand Response Technologies offer incentives to customers who install technologies that are designed to curtail their load when requested to do so by SCE under certain conditions. The rate schedules applicable to Electric Vehicles offer electric vehicle customers time-of-use (TOU) rates designed to encourage charging the vehicles during the most appropriate hours. SCE refers to these currently available rate schedules as "tariffed programs." These tariffed programs are sometimes "riders" to the customer's Otherwise Applicable Tariff, which is defined as the filed rate schedule under which electric service is regularly provided to the customer. For example, a residential customer would receive its normal electric service under Schedule D-Domestic, and if the customer participates in the Summer Discount Plan, the rate schedules under which the customer would receive service would be together under Schedule D and Schedule SDP-Summer Discount Plan. The rules described below further provide the requirements for SCE and the customer when a customer initially applies for electric service, when the load requirements of the customer cause there to be a change in the appropriate rate schedule applicable to the customer, or when the customer requests to interconnect a generating facility.

1. Rate Schedules Offering Incentives for Distributed Renewable Generating Facilities

a) Net Energy Metering

Net Energy Metering (NEM) is an optional tariffed program for SCE customers who choose to install solar, wind, biogas, and fuel cell generating facilities with capacity of one (1) megawatt (MW) or less to serve all or a portion of the customer's onsite electricity needs. The NEM program rules allow SCE to provide simplified and expedited interconnection procedures. NEM is also an electric tariff billing mechanism designed to facilitate the installation of customer-side generation. Today, NEM customers receive a full retail-rate bill credit for power generated by their on-site renewable generating facility. That credit is used to offset the customers' electricity bills, and may be rolled forward to subsequent bills for up to a year, at which time it is "reset" or, in some cases, compensation is paid at the end of the year. Where an NEM customer is paid compensation, the customer's wholesale sales are not subject to FERC's jurisdiction because the NEM customers either meet the requirements for qualifying facility (QF)[168] status or are considered public power entities. QF status is "automatic" (*i.e.,* requires no FERC filing) for certain types of generators (*i.e.*, renewable) 1 MW and smaller. Under the virtual net metering (VNM) concept, the electricity produced by a renewable generating facility is credited towards multiple tenants' accounts without requiring the generating facility to be physically connected to such tenants' meters. The owner or operator of a multi-tenant property designates the percentage of the total metered output of the generator to be allocated to each tenant's service accounts. NEM tariffs currently available to SCE's customers are described below. The NEM tariffs are presently being considered for modification to comply with the provisions of AB 327[169]. The NEM tariffs below are based on their current Commission-approved form.

(1) Schedule NEM: Net Energy Metering

Schedule NEM is available to qualified customers who install and operate a renewable generating facility to supply some or all of the customer's own energy needs. The renewable generating facility must be located on the customer's premises. Customers on Schedule NEM are eligible to receive compensation for net surplus electricity generated by the renewable generating facilities under the auspices of PURPA.

[168] Under the Public Utilities Regulatory Policies Act of 1978 (PURPA), 16 USC § 824a-3, QFs, which are defined under 16 USC 796(17) and (18), are exempt from state and federal regulation as an electric utility.

[169] The Commission adopted R.14-07-002 in July 2014 to develop a successor to existing NEM tariffs, pursuant to AB 327 and PUC Section 2827.1.

(2) Schedule MASH-VNM: Multifamily Affordable Solar Housing Virtual Net Metering

Schedule MASH-VNM is available to qualified customers whose service account(s) are located at a residential complex on the same premises where one or more renewable generating facility has been installed. A qualified customer is either the owner/operator or tenant of a residential complex that qualifies to participate in the California Solar Initiative Multifamily Affordable Solar Housing program or the New Solar Homes Partnership program.

(3) Schedule NEM-V: Virtual Net Metering for Multi-Tenant and Multi-Meter Properties

Schedule NEM-V is available to qualified customers whose service account(s) are located within a multi-tenant and multi-meter property which include all residential and commercial and industrial properties where a renewable generating facility has been installed at a service delivery point (SDP). A qualified customer is either (1) the owner/operator of the multi-tenant, multi-meter property with one or more separately metered accounts, (2) an entity authorized by the owner to install or operate the renewable generating facility, or (3) a tenant/occupant of the property with a separately metered account that is physically connected to the same SDP to which the renewable generating facility is connected.

(4) Schedule FC-NEM: Fuel Cell Net Energy Metering

Schedule FC-NEM is optional to customers who install and operate an eligible fuel cell generating facility to supply some or all of the customer's own energy needs. Customers eligible for Schedule FC-NEM are recipients of local, state, or federal funds or customers who self-finance projects designed to encourage the development of fuel cell electrical generating facilities. Customers with fuel cell generators receive credit for energy generated that exceeds onsite energy demand based on a TOU rate schedule.

(5) Schedule BG-NEM: Biogas Net Energy Metering

Schedule BG-NEM is optional to customers who install and operate an eligible biogas digester generating facility to supply some or all of the customer's own energy needs. Customers eligible for Schedule BG-NEM are recipients of local, state, or federal funds, or are customers who self-finance projects designed to encourage the development of Eligible Biogas Digester Electrical Generating Facilities. This Schedule is closed to new customers.

(6) Schedule RES-BCT: Schedule for Local Government Renewable Energy Self-Generation Bill Credit Transfer

Schedule RES-BCT allows local governments or public college campuses[170] in SCE's service territory to generate energy from a renewable generating facility for its own use (generating account) and to export energy not consumed by the generating account to SCE's electrical grid. The exported energy is converted into bill credits, in dollars, that are applied to eligible benefiting accounts on the same campus, as designated by the local government or college/university. Credits are determined based on the TOU rate. Generators must be sized to offset either a portion or all of the load from the generating account. Designated benefiting accounts can go up to a maximum of 5 MW. This program is subject to statutory megawatt limits by utility.

b) Schedule Re-MAT: Renewable Market Adjusting Tariff (Re-MAT)

Schedule Re-MAT is a renewable energy feed-in tariff available to renewable generators up to 3 MW in size. SCE offers 10, 15 or 20-year power purchase agreements to purchase wholesale power generated from these resources under the auspices of PURPA.

170 "Local government" is defined as a city, county (whether general law or chartered city and county), special district, school district, political subdivision, or other local public agency (e.g. water companies, sanitation districts) which does not sell electricity exported to the electrical grid to a third party, is authorized by law to generate electricity, but shall not mean the state, any agency or department of the state, or joint powers authority, other than a "Campus." "Campus" is defined as an individual community college campus, individual California State University campus, or individual University of California campus.

The energy price is determined by a market adjusting mechanism based on subscription rates.

c) Schedule WATER: Water Agency Tariff for Eligible Renewables

Schedule WATER is an optional tariff for customers who meet the definition of an Eligible Public Water Agency or Wastewater Agency who own and operate a renewable generating facility. SCE offers 10, 15 or 20-year power purchase agreements to purchase wholesale power generated from these resources under the auspices of PURPA. The energy price is set at the applicable Market Price Referent. This Schedule is closed to new customers.

d) Schedule CREST: California Renewable Energy Small Tariff

Schedule CREST is an optional tariff for customers who do not meet the definition of an Eligible Public Water Agency or Wastewater Agency who own and operate a renewable generating facility. SCE offers 10, 15 or 20-year power purchase agreements to purchase wholesale power generated from these resources under the auspices of PURPA. The energy price is set at the applicable Market Price Referent. This Schedule is closed to new customers.

e) Schedule CHP: Combined Heat and Power Excess Energy Purchase

Schedule CHP and associated power purchase agreements are available to customers who own and operate an eligible CHP system that does not exceed 20 MW. Customers with eligible CHP systems may execute a power purchase agreement to sell wholesale power to SCE under the auspices of PURPA. CHP systems located within a CAISO Local Resource Adequacy area may be eligible to earn a ten (10) percent location bonus.

2. Rate Schedules Offering Incentives for Demand Response Technologies

a) Schedule TOU-BIP: Time-of-Use, General Service Base Interruptible Program

Schedule TOU-BIP is optional for medium to large power commercial and industrial customers and Aggregators[171] who have monthly maximum demands or aggregated monthly maximum demands reaching or exceeding 200 kW. Eligible customers must choose a participation option, which is the amount of time (15 or 30 minutes) the customer requires in order to respond to a TOU-BIP event by interrupting or curtailing their load. Customers must make a commitment to reduce at least 15 percent of their maximum demand (but no less than100 kW) during TOU-BIP events. In exchange for participating in the program, customers or aggregators receive monthly bill credits based on the difference between their average peak period demand for each month and their selected Firm Service Level.[172]

b) Schedule AP-I: Agricultural and Pumping Interruptible

Schedule AP-I is optional for agricultural and pumping customers with a measured demand of 37 kW or greater, or with a connected load of 50 horsepower or greater and who elect to interrupt or curtail all of their load instantaneously during an AP-I event. In exchange for participating in AP-I, customers receive monthly bill credits based on the customer's monthly average kW demand recorded during each TOU period (on peak and mid-peak during the summer season, and mid-peak during the winter season).

c) Schedule CBP: Capacity Bidding Program

The CBP has a Day-Of Option and a Day-Ahead Option that are available to Aggregators. Qualified customers receive payments for agreeing to reduce load when a CBP

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171 An Aggregator is an entity that aggregates one or more service accounts of one or more end-use customers.

172 Firm Service Level is the Maximum Demand SCE is expected to supply and/or deliver during any Period of Interruption.

event is called based on the amount of capacity reduction nominated each month, plus energy payments based on actual kWh energy reduction.

d) Schedule DBP: Scheduled Demand Bidding Program

Schedule DBP is a year round bidding program that offers day-ahead price incentives to customers for reducing energy consumption during a DBP event. A DBP event may be called at SCE's discretion, when needed based on CAISO emergencies, day-ahead load and/or price forecasts, extreme or unusual temperature conditions impacting system demand and/or SCE's procurement needs. Customers may place energy bids on a day-ahead basis, but will only receive bill credit based on the actual level of energy reduced during a DBP event.

e) Schedule D-SDP: Domestic Summer Discount Program Plan

Schedule D-SDP is optional to domestic service customers residing in an individually metered single-family accommodation with central air conditioning. Under this Schedule, the customer's air conditioning compressor is subject to disconnection, as initiated by an SDP Event trigger by SCE through a direct load control device, with or without optional customer-controlled override capabilities.

f) Schedule GS-APS-E: General Service Automatic Powershift

Schedule GS-APS-E is optional to general service customers under SCE's SDP program, where the customer's central air conditioning compressor is subject to disconnection, as initiated by an SDP Event trigger called by SCE through a direct load control device. The customers may choose from three cycling options and saving levels--30%, 50%, and 100%--and receive bill savings accordingly.

g) Experimental Schedule UCLT: Utility-Controlled Load Tests

Experimental Schedule UCLT is applicable to load deferral or load shedding and automatic electric power management (Powershift) test programs where a portion of customer's electrical load is subject, on a selective basis at SCE's option, to disconnection from SCE's service by SCE through automatic control systems. This schedule is available for new load control pilots and is applicable only to customers selected to participate in tests at SCE-designated test sites.

h) Schedule SLRP: Scheduled Load Reduction Program

Schedule SLRP is available to customers whose average monthly demand is 100kW or above. Such customers can receive kWh credit on their bill for reducing load on prescheduled days and times on weekdays during the period beginning June 1 through September 30.

i) Schedule OBMC: Optional Binding Mandatory Curtailment

Schedule OBMC is optional for customers who can curtail load on the customer's entire circuit, either on its own or through joint participation with other customers receiving service on the same circuit. OBMC exempts participating customers from rotating outages in exchange for partial load curtailment during every rotating outage period. In exchange, customers must make 15 percent of the load on their entire circuit available for curtailment during every rotating outage.

3. Rates Schedules Offering Incentives for Electric Vehicles

a) Schedule TOU-EV-1: Domestic Time-of-Use Electric Vehicle Charging

Schedule TOU-EV-1 is applicable exclusively to the charging of electric vehicles on a separate meter provided by SCE in Single-Family Dwellings concurrently served under a Domestic Schedule.

b) Schedule TOU-EV-3: General Service Time-of-Use Electric Vehicle Charging

Schedule TOU-EV-3 is applicable solely for the charging of electric vehicles on premises or public right-of-way where a separate meter to service the electric vehicle charging facility is requested. The customer's monthly maximum demand must not exceed 20 kW.

c) Schedule TOU-EV-4: General Service Time-of-Use Electric Vehicle Charging – Demand Metered

Schedule TOU-EV-4 is applicable solely for the charging of electric vehicles on premises or public rights of way where a separate meter to service electric vehicle charging facilities is requested. This Schedule is applicable to applies to customers whose monthly Maximum Demand registers above 20 kW but does not exceed 500 kW.

4. Rules That Govern the Provisions of Electric Service

a) Rule 2: Description of Service

Rule 2 describes the requirements related to the delivery of electric service such as phase and voltage specifications, motor protection and starting currents, interference with service, power factor, wave form, etc., and the general provisions under which customers may receive this service from SCE. It includes provisions for both standard and Added Facilities, with Added Facilities being customer-requested facilities that are more than or in substitution for the facilities SCE determines the customer actually needs.

b) Rule 3: Application for Service

Rule 3 outlines a method of applying for service that ensures conformance to state law and SCE's tariffs. It also states some of the conditions and responsibilities of both SCE and the customer in providing and receiving electric service, which are in addition to those specified in the rate schedules.

c) Rule 15: Distribution Line Extensions

Rule 15 defines the limits and establishes the requirements pertaining to the installation of overhead and underground distribution line extensions. Rule 15 sets forth SCE's responsibilities and that of the customer-applicant requesting the distribution line extension. The rule specifies revenue-based allowances for all line extensions which represent the expected revenue generated from the load served by the line extension. If the cost of the line extension needed is greater than the allowance provided by SCE, the customer-applicant will advance the additional costs which are subject to refund.

d) Rule 16: Service Extensions

Rule 16 establishes guidelines for the connection of overhead and underground new and existing service extensions from SCE's distribution facilities to the customer's electrical equipment. Rule 16 sets forth SCE's responsibilities and that of the customer-applicant requesting the service extension. It addresses meter installations, where they can be located, and requirements for multiple occupancy buildings. It also addresses any miscellaneous equipment needed and who is responsible for furnishing the equipment. It further provides requirements and conditions for transformers installed on customer premises, the ownership and maintenance of the facilities, and the customer's responsibility for customer-owned equipment.

e) Rule 21: Generating Facility Interconnection

Rule 21 describes the interconnection, operating, and metering requirements for distributed generation facilities to be connected to a utility's distribution system over which the CPUC has jurisdiction. It also describes the design and operating requirements for a customer's generating facility to ensure the safety of SCE's system. It also discusses the method and priority for allocating SCE's existing line for interconnection, as well as any facilities required for interconnection.

f) Rule 24: Direct Participation Demand Response

Rule 24 establishes the terms and conditions that apply to entities who take part in Direct Participation Demand Response Service. DR Service is offered by the California Independent System Operator (CAISO) and allows a Demand Response Provider or a retail customer to participate or "bid-in" directly into the CAISO wholesale energy market for compensation by the CAISO, in accordance with the market awards and dispatch instructions established by the CAISO.

5. Other Existing Non-Tariffed Customer Incentive Programs

While the Final Guidance asks for a list of existing tariffs and incentives for DERs, it is important to note that tariffs are not the only mechanism through which customers are incented to install DERs. Besides the tariffs outlined above, SCE offers a portfolio of programs that provide an incentive for the installation of DERs. For example, SCE administers the California Solar Initiative (CSI) Program and the Self-Generation Incentive Program (SGIP) that encourage the installation of customer-side renewable generation technologies. The CSI Program provides utility customers with incentives when they install solar electric systems and solar thermal (*i.e.*, solar hot water) on homes, businesses and public sites.[173] Likewise, the SGIP provides California's utility customers with incentives when they install eligible distributed energy resources including energy storage devices, wind turbines, fuel cells, combined heat power generators, pressure reduction turbines, and waste heat capture applications. SCE's EE portfolio is another non-tariffed customer incentive program that provides financial incentives and services to encourage customers to adopt EE measures and practices. The EE program aims to reduce energy consumption by upgrading existing systems and measures in participating homes or businesses. SCE also utilizes a Commission-approved competitive procurement approach for deploying DERs such as the Local Capacity Requirements Request for Offers, Energy Storage Request for Offer, and Solar Photovoltaic Program. Under these procurement programs, SCE solicits DERs from third parties and negotiates contract terms similar to wholesale procurement processes in order to determine the payment for the resources or services. The costs of these programs are allocated to the benefitting customers, which vary depending on the program.

[173] The CSI program is now closed for residential customers and a waitlist has been established for non-residential customers.

C. Recommendation for How Locational Values Could Be Integrated into SCE's Existing Tariffs

The Final Guidance requires SCE to provide recommendations for "how locational values could be integrated into the above existing tariffs."[174] Although SCE acknowledges that the above outlined tariffs that govern or incent DERs could be modified to reflect the locational values, SCE believes future solicitations for resources could be developed to target areas with high locational value.

To the extent locational values could be incorporated into existing tariffs, SCE believes such new tariff provisions should be developed in the tariff's existing, active Commission proceeding (as possible and appropriate) rather than in this DRP proceeding. This is consistent with the Commission's direction that "[t]his [DRP] Rulemaking, and the DRPs that will be filed in 2015, do not intend to supersede policy determinations or programmatic decisions that rightly fall to [other] proceedings." The tariffed-programs outlined in Section B were designed and developed through various Commission proceedings with well-established procedures and included the input of many interested stakeholders. Deferring to the respective tariff proceeding will avoid duplication of effort, prevent conflicting decisions, and permit all of a given tariff's interested stakeholders to participate in developing tariff changes.[175] Furthermore, since the DRP is being established as a system-wide program, the Commission should assure that the costs of any updated programs are properly allocated.

174 Final Guidance, p. 9.

175 If there is no active proceeding to incorporate locational values, SCE recommends that it be directed to file an Advice Letter to propose any modifications necessary.

D. Recommendation for New Services, Tariff Structures or Incentives Applicable to SCE's DRP Demonstration Projects

To facilitate SCE's field demonstration projects—discussed in Section E of Chapter 2—SCE recommends narrowly tailored incentives and services that are intended to serve as a way to encourage DER deployment at a demonstration project's location. Each of these recommendations are for a finite period, after which SCE will evaluate the efficacy of both (1) whether the new incentive increased customer adoption and (2) whether the resources performed as expected and provided additional value at that location.

In Chapter 2 of the DRP, SCE describes its proposed project Demonstration C (DER Locational Benefits).[176] SCE intends for this project to, in part, demonstrate the ability of DERs to meet grid needs (*e.g.*, distribution system needs, local capacity requirements) in a transmission-constrained area. DERs will be required to fully assess the objectives of Demonstration C, so this Demonstration will leverage the work already being done with the Preferred Resources Pilot (PRP) to acquire preferred resources in the Johanna and Santiago substation areas. SCE proposes to incorporate the following recommendations into its strategy to support executing Demonstration C:

- Leverage the existing Distributed Generation Request for Offer;
- Leverage existing EE portfolio to increase incentive levels for certain EE projects; and
- Evaluate how DR can be designed and implemented for local reliability needs.

1. Leverage the Existing Distributed Generation RFO in SCE's DRP Demonstration C Area

SCE is administering a Distributed Generation (DG) Request for Offer (RFO) as part of SCE's PRP, the geographic scope of which encompasses SCE's Demonstration C area. The

176 For more discussion regarding Demonstration C, please see Chapter 2, Section E.3.c.

RFO seeks to procure a total of 50 MW from renewable DG resources. Under the proposed power purchase agreement, the seller may sell the full output or excess output net of coincident load. In lieu of a customer program, the RFO provides SCE with the opportunity to encourage renewable deployment by direct contractual payments with a third-party provider. Selecting resources through a competitive solicitation also helps to minimize costs to customers. This location-based solicitation is, in essence, another pathway to incentivize local DER deployment that addresses both locational and system needs. Generally, competitive solicitations are an efficient and fair way to assure resources are deployed in particular areas.

2. Incent Certain EE Projects Installed in the Demonstration C Area

SCE administers a portfolio of EE programs that provide financial incentives to customers for the purchase and installation of energy efficient equipment. Currently, most of these incentives are standard across SCE's service territory, without preference for any geographic location. As SCE better understands the types of EE and where increased amounts of EE can support local grid needs, modifying standard incentives to have geographic variation may help increase adoption of EE in those locations of particular need. SCE is demonstrating this concept by leveraging existing EE program funding to offer an additional $30/kW to customers within SCE's Demonstration C area[177] who participate in SCE's Commission-approved Calculated EE program in 2015.[178] Based on the effectiveness of this effort, SCE may pursue continuing this type of approach in subsequent years. This demonstration will provide information about how effective the additional incentive was in encouraging participation in EE upgrades, and whether these upgrades had the intended

[177] The additional incentive is available for the entire PRP region, within which Demonstration C is located.

[178] SCE's current EE program portfolio was approved in D.14-10-046.

results. In this instance, the amount of the additional incentive was set at $30/kW in consideration of current energy efficiency cost-effectiveness protocols.

Deploying EE to support distribution needs will require a level of flexibility and customization that exceeds current levels. As a need is identified, and the benefit is determined, a solution package specific to that need will be developed. This may mirror some of the existing pilot activities that SCE is participating in, *e.g.,* Zero Net Energy Schools Pilot or the LED Tube Pilot, or the current incentive increase in Demonstration C area. The cost-effectiveness calculations would need to reflect the locational benefits and cost identified, allowing these modifications to occur on a larger scale.

3. Evaluate How Demand Response Can Be Designed and Implemented for Local Reliability Needs in the Demonstration C Area

SCE recommends evaluating how a Demand Response (DR) offering in the Demonstration C area could support local reliability needs. This could include an evaluation of various possibilities: a trigger for programs that is specific to granular geographic regions, increased flexibility for DR hours (*i.e.,* not just conventional system peak or other pre-established triggers), more shallow responses, faster responses (particularly for integrating renewables), and enhanced telemetry requirements. To this end, Demonstration C could test a DR product designed for and dispatched according to local conditions on the distribution circuits and could alleviate local congestion issues by decreasing load. Better aligning the DR capabilities with local systems needs would ultimately support better distribution system operation. This product could be procured from a third party through a solicitation or developed under SCE's existing Experimental Schedule UCLT: Utility-Controlled Load Test.

E. Recommendation for Further Refinements to Interconnection Policies That Account for Locational Values

The Final Guidance requires SCE to provide recommendation to further refine its interconnection policies by incorporating locational values. The interconnection policies discussed herein focus on Rule 21 interconnection policies under the CPUC's jurisdiction.

1. Rule 21 Overview

As mentioned in Section B of this chapter, Rule 21 governs the requirements as determined by the CPUC for interconnecting distributed generation facilities to SCE's distribution system. On September 22, 2011, the Commission issued an Order Instituting Rulemaking (OIR) to improve distribution-level interconnection rules and regulations for certain classes of electric generators and electric storage resources, R.11-09-011 (Rule 21 OIR). The Rule 21 OIR seeks to "address the key policy and technical issues essential to timely, non-discriminatory, cost effective and transparent interconnection."[179] On September 13, 2012, the Commission approved D.12-09-018, which approved the multi-party Settlement Agreement and concluded the first phase of the OIR. Rule 21 was significantly reformed through this Settlement Agreement. On September 26, 2012, the Commission issued the Assigned Commissioner's Amended Scoping Memo and Ruling Requesting Comments, which established the scope of issues for the second phase of the OIR. Rule 21 continues to be refined as new interconnection processes and standards are implemented by the Commission in this second phase.

2. Further Refinements to Rule 21 to Account for Locational Values

SCE believes that the LNBM described in Chapter 2, could be utilized to address the Commission's desire to further refine interconnection policies to account for locational

[179] *See* Rulemaking (R.)11-09-011, Order Instituting Rulemaking on the Commission's own Motion to Improve Distribution level Interconnection Rules and Regulations for Certain Classes of Electric Generators and Electric Storage Resources, p. 4.

values. However, there is an open Commission rulemaking that is reviewing and revising SCE's Rule 21, the Rule 21 OIR. There are significant Rule 21 interconnection policy reforms underway in that rulemaking, including establishing policies that address: (1) a fixed cost option for certain interconnection projects[180] and (2) an interconnection study process for behind-the-meter, non-exporting energy storage.[181] Due to the Rule 21 OIR's stated scope, and because that rulemaking is actively considering Rule 21 reforms, SCE believes that it is premature to recommend any refinements to interconnection policies that account for locational values.

To the extent locational values could be incorporated into Rule 21, SCE recommends developing any changes to SCE's Rule 21 in the Rule 21 OIR, itself. This will allow any policy determinations and programmatic changes to improve Rule 21, including accounting for locational values, to be reviewed by all interested stakeholders participating in the Rule 21 OIR. This will take advantage of the expertise of all stakeholders and Energy Division staff who have participated in the years-long Rule 21 OIR, and also ensure that changes will not conflict with or negatively affect changes currently being evaluated and implemented in the Rule 21 OIR.

[180] R.11-09-011, Motion of Southern California Edison Company (U 338-E) San Diego Gas & Electric Company (U 902-E), and Pacific Gas and Electric Company (U 39-E) Proposing Rule 21 Tariff Language Implementing Joint Cost Certainty Proposal, dated April 1, 2015.

[181] R.11-09-011, Joint Motion of Southern California Edison Company (U 338-E) San Diego Gas & Electric Company (U 902-E), and Pacific Gas and Electric Company (U 39-E) on Revisions to Streamline Rule 21 for Behind-the-Meter, Non-Exporting Storage Devices, dated April 1, 2015.

Chapter 5:
Safety Considerations

V.

CHAPTER 5: SAFETY CONSIDERATIONS

A. Introduction and Executive Summary

DERs have the potential to provide added grid reliability and resiliency, which improves overall grid safety. For example, photovoltaics combined with energy storage may act as backup generators to the grid in the event of an outage and may also serve as repositories for excess in an over-generation situation. Likewise, DERs have been used and have the potential to be used more widely to flatten the utility's peak load to avoid an outage event. Microgrids have the potential to separate seamlessly from the grid during power system events or outages, and allow customers utilizing such technologies to manage their energy resources under such events. Moreover, DERs can provide needed voltage control to support overall grid reliability.

Correspondingly, large numbers of DERs connected to the grid can also create safety concerns. Certain DER equipment, such as energy storage and PV systems, present particular safety concerns for grid equipment, utility workers, and the general public. These safety concerns can be mitigated or obviated by a combination of grid modernization, enhanced standards, and outreach to government officials.

The Final Guidance requires utilities to include the following four items in their DRPs:

1) Catalog of potential reliability and safety standards that DERs must meet and a process for facilitating compliance with these standards[182] along with an explanation of "differing requirements or standards that should be considered for different types of DERs."[183]

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[182] Final Guidance, p. 9.

[183] *Id.*

2) Description of how DERs and grid modernization could support higher levels of system reliability and safety (*e.g.,* improved SAIDI/SAIFI, resiliency, improved cyber security).

3) Description of major safety considerations involving DER equipment on the distribution grid that could be mitigated or obviated by technical changes.

4) Description of education and outreach activities by which SCE plans to inform and engage local permitting authorities on current best practice safety procedures for DER installation, so that local permitting of DER equipment is not outdated, onerous or overly prohibitive or limiting of otherwise safely and soundly designed projects.

Section B(1) of this chapter provides a list of standards applicable to DERs issued by various independent standards organizations. Section B(2) describes the processes established in California for complying with these standards (*i.e.,* Rule 21 and WDAT), which are the established protocols for interconnecting devices that feed power onto the distribution system. Section C(1) describes potential enhanced grid capabilities that can be achieved from DERs, coupled with grid modernization investments. Section C(2) delineates the potential grid modernization solutions needed to enable these enhanced grid capabilities. Section D describes the specific safety considerations that energy storage and PV equipment and the technical changes that obviate or mitigate these concerns. Finally, Section E details current education and outreach activities related to energy efficiency and highlights opportunities for additional education and outreach.

B. Identification of Potential Reliability and Safety Standards That DERS Must Meet and a Process for Facilitating Compliance with These Standards

1. Reliability and Safety Standards Applicable to DERS

Standards play a key role in a number of industries, protecting workers and consumers by ensuring that equipment operates according to required specifications. The electric industry is no different. Standards are developed to ensure that equipment operates in a safe and predictable manner. Standards also guide workplace practices and safety requirements with respect to the operation and maintenance of such equipment. Standards are not typically static and must evolve with changes in operating requirements and technology advancements, among other factors. This is particularly true with respect to DERs as policies and technologies continue to evolve. Standards organizations that develop requirements for interconnection equipment, installation, and operation have developed standards to address DERs and are continuing to refine these standards. Currently, the following four standards organizations set reliability and safety requirements for DERs:

- Institute of Electrical and Electronics Engineers (IEEE)
- Underwriters Laboratories (UL)
- International Electrotechnical Commission (IEC)
- National Electric Code (NEC)

All of these standards organizations are independent, nonprofit organizations. Each organization has a separate and distinct mission and objectives. The IEEE is a national organization that develops voluntary consensus standards on electric technologies. The IEEE collaborates with the American National Standards Institute (ANSI), a nonprofit organization that oversees the development and use of voluntary consensus based standards across the U.S. The IEC is an international organization that also develops voluntary consensus standards on electric and communications protocols and technologies. The UL is a safety certification organization and usually incorporates IEEE, ANSI and IEC requirements in their standards. The UL has a number of certifications applicable to interconnection equipment associated with DERs. The NEC addresses standards for electric conductors and equipment installed within or on buildings that are not part of a generating plant, substation, or control center.

The following reliability and safety standards and certifications have been developed for DERs that feed power onto the grid:

- IEEE 1547-2003: Standard for Distributed Resources Interconnected with Electric Power Systems. This series of standards is the U.S. standard for interconnecting DERs and is universally adoptable, technology neutral, and covers any DERs as large as 10 MW. Specifically, this series of standards defines the minimum functional technical requirements for performance, operation, testing, safety and maintenance of all types of DERs. IEEE 1547 is a requirement for interconnecting to SCE's system, as stipulated in SCE's Rule 21 tariff, as well as in the Net Energy Metering (NEM) Handbook. This document was developed to facilitate customer understanding regarding interconnection of solar PV and the NEM program.
- ANSI/IEEE 929-2000: Recommended Practice for Utility Interface of Photovoltaic (PV) Systems, addresses power quality, equipment protection and safety. This practice describes the requirements and safety practices necessary for a photovoltaic system to interconnect.
- UL 1741: Inverters, Converters and Controllers for Use in Independent Power Systems, addresses inverters, converters, charge controllers, and output controllers for both non-grid and grid-connected power systems. Most cities or counties require a UL certification before allowing installation of this equipment on the customer side of the meter.
- NEC, 705, Interconnected Electrical Power Production Systems broadly covers DER interconnection. It applies to any power-production system connected to the utility through an inverter, regardless of the energy source—examples include generators, PV systems, wind turbines, electric vehicle charging stations and fuel cells.

SCE is working with a number of other organizations to modify existing standards, as discussed later in this chapter. SCE encourages the use of open standards based equipment to increase options and reduce costs. In particular, SCE is actively engaged in efforts to revise the following standards related to DERs:

- IEC 61850: Power Utility Automation, covers substation automation. Specifically, this standard addresses the communications architecture and data transfer required for protective relaying – opening a circuit breaker when a fault is detected. The IEC 61850 abstract data information model has been selected as providing the basis for the communications required for the Phase 1 functionalities and Phase 3 functionalities as currently under review as part of the Rule 21 Smart Inverter Working Group (SIWG).[184] Ultimately, this standard can enable inverters to perform "smart" functions, such as local voltage support and riding through significant voltage and frequency variations.
- IEEE 2030.5: Also known as the Smart Energy Profile (SEP) 2.0, defines a set of protocols for utility management of end-user energy devices. The standard contains attributes and control functions for applications such as demand response, load control, pricing, and DER management. This standard can provide additional data from inverters (*e.g.,* voltage, status on/off, etc.) and the control functions enable grid support (*e.g.,* reactive power support, ability to go off-line if needed, etc.). This standard proposed by the SIWG is to be utilized for interconnections governed under Rule 21.

[184] SIWG is a joint CPUC-CEC working group to explore and define the technical steps needed to integrate inverter-based DER functionalities and allow efficient management of the distribution system while maintaining standards of reliable and safe. *See*, http://www.cpuc.ca.gov/PUC/energy/June_21_2013_Smart_Inverter_Functionalities_Workshop.htm.

- IEEE 1547 is being revised to update DER interconnection requirements, to address interoperability, which better defines how disparate DER systems interact with each other and the grid. This is similar to the computer industry's adoption of the Universal Serial Bus (USB) standard, which ensures device compatibility (*e.g.,* thumb drives, computer mouse, external hard drives). Consistent with the purpose of such standards, this can improve operational predictability and safety. Importantly, these revisions should reduce interconnection approval times by standardizing the requirements.

2. Process for Facilitating Compliance with Potential Reliability and Safety Standards

The majority of the standards and certifications noted above have been incorporated into Rule 21 and the WDAT (except for IEC 61850 and IEEE 2030.5, which are likely to be incorporated as technology evolves). Furthermore, ANSI/IEEE 1547-2003 has been harmonized with Rule 21[185] and has been incorporated into the WDAT. These standards have also been integrated into the NEM Handbook, which is publically available via SCE's website.[186] DERs must adhere to Rule 21[187] or WDAT prior to interconnecting to the grid.

DERs must be technically reviewed by SCE engineers, as part of the interconnection process under Rule 21 and the WDAT. Moreover, to be eligible for SCE's NEM Program, technical review by SCE engineers is also required. Whether a generator interconnects

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185 Southern California Edison Advice 3030-E, California Energy Systems for the 21st Century Proposed Research and Development Projects and Cooperative Research and Development Agreement, Rule 21, Generating Facility Interconnections, Tariff Sheet 10.

186 https://www.sce.com/wps/wcm/connect/69531af9-15f6-43e1-8368-a195c65fa249/NEM_Interconnection_Handbook.pdf?MOD=AJPERES&projectid=47ce3725-0471-4b64-bc8f-53307ec2c94d&projectid=47ce3725-0471-4b64-bc8f-53307ec2c94d.et

187 The design must also be in accordance with SCE's Electric Service Requirements, SCE's Interconnection Handbook, the National Electric Code and all applicable local codes and ordinances.

under Rule 21 or the WDAT, technical review requires confirming that inverters associated with PV systems meet IEEE 1547 and UL 1741 standards.[188] If interconnecting under Rule 21, technical review also includes a commissioning test for all distributed generation projects greater than 10 kW.[189] Frequency requirements are verified during the commissioning test, per Rule 21, Section H.[190] Similar to Rule 21, interconnecting under the WDAT also provides SCE the ability to review DER equipment prior to installation, during pre and post commercial operation testing. Both Rule 21 and the WDAT require an Electrical Inspection Release (EIR) from the appropriate local authority having jurisdiction to verify that the work on the customer's side of the meter meets the requirements of the NEC and all applicable local codes and ordinances.

To incorporate increasing numbers of DERs onto the grid, further upgrades to communications, voltage control schemes, monitoring, and protective relays are needed. These changes may require further revisions to reliability and safety standards in general and ANSI/IEEE1547, in particular. Future workshops to review updates to these standards may be needed.

Cybersecurity represents an emerging and critical issue to grid security and overall grid reliability. Introducing digital monitoring and control devices on the distribution system promotes the reliable integration of DERs, but it also increases the number of points on the grid that are vulnerable to cyberattacks. The North American Electric Reliability Corporation (NERC) has addressed this issue at the transmission-level and developed broad standards for protecting the U.S. grid (the "bulk electric system") called Critical Infrastructure

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188 SCE, Net Energy Metering Interconnection Handbook, p. 11.

189 Projects less than 10 kW are evaluated on a case-by-case basis.

190 SCE, Net Energy Metering Interconnection Handbook , p. 8., *Also see* SCE Rule 21 Tariff, Generating Facility Interconnections.

Protection (CIP). SCE has participated in developing these standards and is deploying compliance solutions. SCE can apply this experience and knowledge to develop standards for the distribution system.

C. Description of How DERS and Grid Modernization Can Support Higher Levels of System Reliability and Safety

1. Potential Enhanced Grid Capabilities from DERS

DERs can potentially mitigate energy disruptions, which mitigation is fundamental to infrastructure resiliency.[191] Better grid resiliency improves the reliability and safety of the grid. DERs can provide enhanced resiliency and reliability by providing the following enhanced grid capabilities:

- Riding through significant voltage and frequency variations
- Microgrids
- Local voltage support
- Increased monitoring

a) Voltage Support

DERs can potentially support grid reliability during system problems by providing power to the grid during significant voltage and frequency variations. Large voltage and frequency variations, usually caused by transmission line faults or failure of large generators, can compromise grid stability and reliability. If sufficient amounts of DERs are deployed and remain connected to the grid during such events, the DERs can help maintain the integrity of the grid by supporting voltage levels.

Current interconnection standards require DERs to disconnect from the grid during outages, to avoid DERs feeding power onto a de-energized circuit, unbeknownst to electricity

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[191] Quadrennial Energy Review (QER) Report: Chapter 2, *Increasing the Resilience, Reliability, Safety, and Asset Security of TS&D Infrastructure* (April 2015), p. 2-2. *See* http://energy.gov/sites/prod/files/2015/05/f22/QER%20Full%20Report_0.pdf.

workers and the public. Engineers across the country are working to develop and incorporate new operating methods and technologies that enable DERs to remain safely connected to the grid until it is determined that such devices can no longer maintain voltage, at which point the DERs would automatically be disconnected. Updating the standards to reflect these advances can allow DERs to provide this voltage support value to the grid.

b) Microgrids

DERs functioning as a microgrid can provide improved reliability, through separation from the grid during power system problems or outages. Microgrids that are still connected to the grid also have the potential to help with grid stability by acting as a controllable load through adjustment of the microgrid's generation, storage, or customer demand. These microgrids may serve as load sinks (that is, a repository for excess generation) or capacity, as needed, to support grid reliability.

c) Local Voltage Support

Utilities typically maintain voltage within prescribed levels on the distribution system using capacitors and voltage regulators. Inverter-based DERs, such as PV or battery storage, have the potential to provide local voltage support by injecting power, as needed. This additional voltage support would enhance grid reliability and safety. As technologies and operating methods continue to advance, these functions will be implemented through ongoing revisions to IEEE1547, UL 1741 and California's Rule 21.

d) Grid Operations Enhancements

As technologies continue to evolve and more DERs are connected to the grid and have the potential to be aggregated, obtaining operating information from DERs or from their point of interconnection can allow SCE engineers and grid operators to better understand what is happening on the grid and develop solutions in real-time. Currently, many of the DERs connected to the grid are not monitored or coordinated. System engineers and operators have little feedback regarding DER operations and how DERs might impact or be utilized to support grid operations. This additional information can help to further unlock the benefits that DERs can provide by supporting grid operations.

2. Potential Grid Modernization Needed to Enable Enhanced Grid Capabilities from DERS

To maximize DER benefits, parties must proactively address any safety issues associated with the deployment of substantial numbers of DERs and must also put in place the foundational technology that would enable DERs to provide the safety benefits outlined above.

As greater numbers of DERs (and in particular, PV generation and storage) are installed on the distribution grid, a number of safety issues emerge. For example, DERs create variations in customer voltage caused by intermittency, (*e.g.,* when clouds passing over PV panels). DERs can overload transformers, circuit conductor, and circuit breakers due to DER generation or storage charging. Likewise, DERs can create longer-term grid challenges, for example, protection of longer circuits in the presence of large amounts of DERs since the generation makes it harder to detect faults at the ends of the circuit; improper fault location indications due to reverse power flows leading to extended fault location and need for repair, and potential for improper switching decisions based on missing DER generation information offsetting circuit loads.

These potential reliability issues, however, can and should be addressed through grid modernization investments.   SCE grid investment plan is designed to deploy the following technology solutions to maintain the safety and reliability of the grid as DER integration grows.

a) Communications Needed to Fully Integrate DERS

Improved communications systems will be needed to allow for safe and secure coverage of automated devices across the grid. These communications upgrades, such as fiber optics networks (Ch. 7; GM #6), can support the transfer of large amounts of system data. The fiber optic network in combination with local field area networks (Ch. 7; GM #5) enables retrieval of information and execution of control actions on a real-time basis. These communications systems can allow integration of existing equipment (remote controlled switches, capacitor controllers and monitors) with new technologies (inverter VAR control, communicating fault indicators/circuit monitors and intelligent switches) designed to improve safety and reliability.

b) Voltage Control Devices to Avoid Voltage Fluctuation

DERs can alter existing distribution circuits loading patterns during generation and the performance of existing voltage support devices. Moreover, existing voltage control devices were designed to maintain voltage at mandated California Rule 2 levels[192] by correcting for voltage drop due to radial power flow. Since the distribution circuits' loading patterns change because of DERs' intermittent generation, the existing voltage control devices may no longer provide proper voltage regulation, which, if allowed to persist, could cause failure of utility and customer equipment.

The existing voltage support devices such as capacitors, voltage regulators, and transformers can be supplemented by smart inverters connected to PV and battery energy storage devices to provide this voltage regulation. SCE may need to deploy Volt/VAR control schemes (Ch. 7; GM #15) to manage voltage and power factor across distribution circuits. These system upgrades are essential to maintain grid reliability and mandated voltage levels on the distribution system.

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192 SCE Tariff Rule 21, Generating Facility Interconnections, Sheets 103-104, limits residential and commercial circuit voltages to +0% / -5% of nominal service voltage. Industrial and agricultural circuit voltages range from -5% to +5%.

c) Grid Reinforcement for Resiliency

Circuit and substation equipment, including circuit conductors, transformers, fuses, and substation breakers, was initially designed to accommodate power flow from the substation to loads. Now with power flowing in a reverse direction at times, these components may not be properly sized. The interconnection of DERs on distribution circuits might overload circuit and substation equipment causing premature equipment failure reducing reliability.

Installation of heavier circuit conductors on the main lines of the circuits (Ch. 7; GM #16) can position these circuits to handle such bidirectional flows, more easily interconnecting DERs. Interconnection studies for DERs can also identify places where transformers, fuses, and substation breakers would be undersized and make provisions for them to be upgraded.

d) Modernization of Protection Relays

Existing protective relays are specified and set to operate unidirectionally (from substations to loads) at the current fault duties and coordinated with downstream protective devices to insure only the least amount of customers will be interrupted. Multiple DERs on the feeders can mean there are many power sources on the circuit and this makes protection and coordination studies much more complex. In many cases, the existing unidirectional protective relays may need to be replaced with bidirectional or other advanced relays to ensure proper protection. Modern protective relays (Ch. 7; GM #4) are designed to handle bidirectional power flows without disrupting protective functionality.

e) Replacement of Fault Indicators

Existing fault indicators may not work properly with increasing amounts of DERs, because they are based on unidirectional power flow design. If these devices are not replaced with bidirectional devices, in the presence of significant DERs, grid operators may be misled about the locations of faults, which could delay outage restorations. Remote fault indicators (Ch. 7; GM #2) can provide basic telemetry, as well as immediately indicating system failure locations, which results in decreased response time. Finally, DERs could potentially provoke unintended flickering through generation variations caused by cloud cover or wind speed variations. SCE may need to install power quality recorders to detect these events and try to reduce this problem.

f) Demonstration and Testing for Microgrids

Microgrids have the ability to separate seamlessly from the grid during power system events or outages. Once islanded, it is important to the islanded customers to maintain microgrid reliability for customer loads. The transition from a grid-connected microgrid to islanded microgrid and back also needs to be done properly to avoid loss of customer loads and to protect public safety. Moreover, microgrids also could be operated in a manner that would harm customer reliability, by increasing grid load during peak times and allowing customer voltage and frequency to vary while islanded (when islanded the microgrid controller maintains voltage, frequency and load/generation balance). Therefore, additional demonstrations are needed to evaluate the reliability impacts of microgrids on the distribution system. Such reliability impacts may necessitate technology platforms and applications investments. (*See*, e.g., Ch. 7; GM #7-15 for technology that could be used to, among other things, mitigate safely impacts and would enable a safe integration of microgrids. However, additional information needs to be developed to understand more fully the safety impacts of microgrids and the technology needed to avoid those impacts.

g) Prevention of Cybersecurity Risks

While an increasingly decentralized grid resulting from high penetrations of DERs may ultimately reduce cybersecurity exposure, in the short-run DERs increase the risk for cybersecurity attacks. DERs increase grid communications and automation, which provide more entry points for hackers and others to disrupt the operation of the grid. Such disruption could cause a system outage, damage to distribution equipment, and harm to public and employee safety. As greater numbers of DERs become interconnected, it becomes increasingly important to establish standardized protective measures for these devices to ensure that they do not render the grid more susceptible to physical[193] or cyberattacks.

To protect against cyberattacks, it is imperative that SCE modernize its grid with additional visibility through increased sensing utilizing secure communications, computing, and control infrastructure. A modern grid with enhanced visibility and cybersecurity capabilities should be able to detect, isolate, or reroute power to mitigate potential damage to the grid. SCE is in the process of developing a proprietary cybersecurity solution (Ch. 7; GM #14) for the grid.

Another important element to modernizing the grid is ensuring that all inverters[194] supporting DERs conform to cybersecurity standards. Implementing these IEC, NIST and DHS standards provides inverters with appropriate software safeguards to prevent cyberattacks. If appropriate grid modernization efforts are made, including securing substations and inverters enabled with cybersecurity standards, coupled with investments in cyber protection schemes, DERs can potentially support grid resiliency.

h) Potential Impacts to Reliability Reporting

With appropriate short and long term investment support from SCE's grid modernization program, DERs can contribute to improvements to safety and reliability metrics, such as System Average Interruption Duration Index (SAIDI), System Average

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[193] The Commission recently issued a white paper, *Regulation of Physical Security for the Electric Distribution System,* on physical security of the grid. This white paper may initiate additional Commission actions. SCE is monitoring these future Commission actions to evaluate any impacts on DERs in general and specifically future DRP application filings. *See* http://www.cpuc.ca.gov/NR/rdonlyres/930FCC00-BE2F-4BCF-9B68-2CA2CDC38186/0/PhysicalSecurityfortheUtilityIndustry20150210.pdf

[194] Currently, only European inverters conform to cybersecurity IEC standards.

Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI). This is because with increased levels of distribution automation (Ch. 7; GM #1) facilitating DER integration, a small group of homes would lose power from a system fault, rather than most of the homes on the circuit, improving SAIDI, SAIFI and MAIFI metrics.

D. Description of Major Safety Considerations Involving DER Equipment on the Distribution Grid That Could Be Mitigated or Obviated by Technical Changes

DER equipment connected to the grid poses a variety of unique safety considerations. The various types of DERs have different safety considerations, depending on the technology used, and the location and size of the installation.

In general, safety risks are being mitigated through three technical changes: (1) appropriate safety validation procedures; (2) appropriate procedures to respond if safety incidents occur; and (3) appropriate safety codes, standards, and regulations. One challenge is that local authorities typically have jurisdiction over inspections and necessary permits and these authorities have differing standards.

1. Energy Storage/Fuel Cell Systems

As explained below, the type and severity of safety issues arising from energy storage systems vary depending on where the energy storage system is deployed. An energy storage system deployed in a remote, rural location poses less safety risks, than a system installed in residential or urban high-density environments. Energy storage systems in residential or urban environments pose a larger safety risk, due to the greater number of people in close proximity that could be affected, compared to rural installations.

Historically, battery systems were installed in commercial or industrial sites accessed by only service professionals. However, energy storage systems are expected to appear in publicly-accessible commercial and residential locations and steps must be taken to assure that the general public does not have access to high-voltage electrical parts. SCE is mitigating these risks by ensuring that energy storage systems that SCE installs are housed in secure enclosure to prevent such access. SCE has no control over behind-the-meter energy storage systems that SCE does not install.

Battery energy storage systems' chemical makeup also poses a safety concern. For instance, lithium ion batteries pose a safety risk due to the combustible nature of the battery electrolytes and the metal oxide electrode materials at elevated temperatures. However, by leveraging the extensive energy storage validation procedures and engineering safety designs for plug-in electric vehicle (PEV) battery systems, such safety concerns are being mitigated, at least regarding SCE-owned or controlled systems.

Batteries are also susceptible to being overcharged and over-discharged, which pose a potential safety risk of so called "thermal runaway" -- a rapid uncontrolled increase in temperature that cannot be halted, even if the system is stopped or disconnected. Thermal runaways pose a fire hazard. Moreover, a thermal runaway can cause damage to the DER equipment that connects the battery to the grid. These events can be prevented from occurring through the implementation of voltage safety monitoring and controls and fault detection mechanisms at both the battery cell level and system level. SCE has deployed such controls, as part of its energy storage deployments, (*e.g.,* Irvine Smart Grid Demonstration, and Tehachapi Storage Project).

Batteries that release flammable gases, such as hydrogen fuel cells and in the case of lead-acid batteries, can present a fire hazard to vehicles and potentially to homes. This risk is mitigated through an engineered ventilation system and safety release valves equipped on the device to prevent thermal runaway.

All hydrogen fuel systems have the potential for small leaks. Since hydrogen has a high dispersion rate, small leaks could lead to accumulation of hydrogen, which poses a fire hazard. Proper ventilation would mitigate this risk. While not a requirement, the best practice of installing hydrogen detectors, which function similar to fire detectors, provides additional protection.

2. PV Systems

PV systems can create power quality and frequency regulation issues due to changes for sun hitting the panels. At high penetrations of PV, these solar input variations can cause significant PV power output fluctuations. This can cause flickering and problems with balancing load and generation which can contribute to degradation of grid stability. Consequently, it is essential that PV systems conform to standards that regulate inverter voltage and frequency limits as well as meet emerging rule modifications (Rule 21 revisions are currently underway) that allow utilities to modify PV array output. Another way to reduce PV array output is to balance them, using a storage system or load control. In any event, the proliferation of these types of devices requires additional telemetry so that operators, engineers and planners have the situational awareness needed to support the safe, affordable and reliable delivery of energy services to customers.

Another important safety concern associated with PV is unintentional islanding. Unintentional islanding occurs when the PV system continues to energize a utility wire after being disconnected from the rest of the grid following an electrical system fault or utility switching action. Unintentional islanding can pose the following risks:

- Exposure to energized conductors that should be de-energized creates a safety hazard for utility personnel, emergency responders, and the public;
- Transient overvoltage or out-of-phase reclosing (re-energizing an inverter originally connected to the grid before the inverter has safely shut down) could cause potential damage to DER systems and utility-owned equipment if DERs are reconnected to the grid while still operating;
- Increase in restoration time caused by the need to isolate a PV system that did not shut down correctly may reduce reliability;
- Distribution circuit breakers may exceed their fault current ratings(the fault current level that can be safely interrupted by the circuit breaker); and

- Current voltage regulation schemes may stop working properly.

These risks are usually mitigated by PV inverters with anti-islanding features built into the controls and certification under the requirements of IEEE 1547. However, unintentional islanding remains a concern when PV is connected to other distributed generation such as a synchronous (*e.g.,* diesel) generator that could deceive anti-islanding features. The synchronous generator can cause a feeder to unintentionally remain energized even when disconnected to the grid. Again, additional telemetry will provide the situational awareness needed to support the safe, affordable and reliable delivery of energy services to customers.

E. Description of Education and Outreach Activities by Which the Utility Plans to Inform and Engage Local Permitting Authorities on Current Best Practice Safety Procedures for DER Installation

1. Current Education and Outreach Activities Related to Energy Efficiency

SCE currently engages government authorities through the California Statewide Codes and Standards (C&S) Program. The C&S Program is a program jointly implemented by the IOUs[195] and the CEC. As part of this Program, the CEC triennially conducts a rulemaking process for updating the State's EE building code and appliances standards. Following adoption of such updated codes and standards,[196] SCE's C&S Compliance Improvement (CI) Subprogram[197] educates and trains local authorities on compliance. SCE's Energy Codes &

[195] The IOUs in this instance are defined as PG&E, SDG&E, Southern California Gas Company (SoCal Gas), and SCE.

[196] California Code of Regulations, Title 24, Part 6, and Title 20. Public Utilities and Energy.

[197] The CI Subprogram targets market actors throughout the entire compliance supply chain, providing education, outreach, technical support, tools and resources to increase compliance with both the building and appliance energy standards. The CI Subprogram is guided by the Compliance Improvement Advisory Group (CIAG). The CIAG is made up of the Joint-IOUs (see footnote 14), members of more specialized advisory groups (*e.g.,* Heating, Ventilation, Air-Conditioning (HVAC) Compliance Alliance), and relevant practitioners.

Standards Reach Code Subprogram also provides technical support to localities seeking to adopt more aggressive EE codes than those adopted by the CEC.

One such important education effort is the Energy Code Ace website, (energycodeace.com). Energy Code Ace, provides comprehensive, free energy code training, tools, and resources to help inform local authorities understand how to meet compliance for the State's building codes.

2. Opportunities for Additional Education and Outreach

As DER installations become more prevalent, informing local permitting authorities of current best practices, through education and outreach activities, becomes increasingly important. SCE plans to share DER best practice procedures for DER installations with local permitting authorities in a cost-effective manner, by leveraging its sce.com website, by utilizing our contacts with local jurisdictions in our Local Government Partnerships Program, and by using our existing relationships with DER market contractors and vendors.

These best practices on SCE's website could include information for local authorities on state and national efforts organized by industry groups attempting to standardize local jurisdictional requirements for permitting DERs. Currently, local jurisdictional requirements greatly vary in complexity for permitting DERs. If local authorities standardize these local jurisdictional requirements, it would improve the safety of DER installations. Additionally, SCE could include information on its website educating local authorities of the potential fire hazard that PV systems and energy storage systems present for first responders, especially as DER installations increase and in particular in residential areas. These specific hazards include:

- Electric shock: Firefighters could come into contact with solar panels still generating electricity from exposure to sunshine, or the flood lights used during nighttime emergency responses.

- Density of PV panels: Firefights commonly create a hole in the roof for ventilation to contain fire incidents. If there are too many panels, it becomes difficult to create an adequate hole for ventilation. Moreover, if a firefighter is not aware of a PV panel prior to creating such a hole on the roof, such potential incidental contact creates an electric shock hazard.
- Weight of PV panels: Roofs compromised by fire could potentially collapse with the additional weight of PV panels. PV panels could also release harmful chemicals if exposed to fire.

One potential online opportunity to mitigate this fire hazard is to publish information on the website about efforts in other states where local permitting authorities have established an energy emergency database (EED) for homeowners' to self-register their PV and/or energy storage systems.[198] This EED can interface with emergency response databases to make first responders aware of a PV and/or energy storage system's presence if an emergency occurs.[199]

Other education and outreach online activities could include informing local permitting authorities on how to comply with the California Fire Code (CFC) Section 605.11 for PV installations. In the past, local authorities were responsible for fire safety considerations of PV installations. However, on January 1, 2014, the CFC became effective and superseded local fire municipal code. The CFC's provisions for PV installations are similar to many local ordinances. One important difference though is the CFC established a new State spacing requirement for roof access and pathways[200] to areas of the roof for first

198 For a discussion on this barrier and SCE's recommendation for how to overcome it, please see Chapter 6: Removing Barriers to Deployment.

199 New Jersey requires building owners to notify local fire officials of roof-mounted solar panels, per N.J. Stat. § 52:27D-198.17 (2015)). Moreover, the Federal Network Agency in Germany has set up a similar central registry and first responders have found the database valuable.

200 California Fire Code, Subsection 605.11.3: Access and Pathways.

responder smoke ventilation operations.[201] CFC's spacing requirements for roof and pathway access differs from municipal past practices. Therefore, educating local permitting authorities on this new requirement is key to ensuring compliance with the CFC. As a successful example of this approach, in April 2015 SCE teamed up with the City of Los Angeles Building & Safety division, to host a "Solar Training & Education Seminar" attended by Building & Safety officials and Fire Prevention officials, from 55 cities in SCE service territory. SCE could work with local public officials to determine if and what kind of similar educational efforts or workshops may be useful on DER safety issues.

Another opportunity would include teaming up to share the best practices information through our existing channels with local jurisdictions, as we currently have Local Government Partnership Agreements in place with 150 Cities and Counties in SCE service territory. These partnership arrangements allow us to have access to and provide information quickly to officials in these areas. These partnership channels could be used to distribute the solar PV fire safety; interconnection safety; and permitting best practices information discussed previously. The distribution methods (printed collateral; electronic documents; etc.) could be evaluated on the basis of cost effectiveness and partnership agency preference. For example, some cities would have a preference for information that could be uploaded on their website.

[201] Heat and smoke rise, therefore venting the roof allows flammable and toxic gases, as well as dark smoke to escape. Moreover, venting the roof improves the visibility for first responders; reduces the possibility of a backdraft, because heat, flammable and toxic gases have been reduced; and improves the chances of survival for victims, because more oxygen is present.

Chapter 6:
Overcoming Barriers to Deployment of DERs

VI.

CHAPTER 6: OVERCOMING BARRIERS TO DEPLOYMENT OF DERS

A. Introduction and Executive Summary

1. Introduction

Today's distribution grid, regulatory processes, standards, and ratemaking mechanisms were originally designed to accommodate the one-way flow of energy and energy services – from central generation stations to individual homes and businesses. SCE anticipates that in the future, the electrical power system will reflect the three goals identified by the Commission in the DRP OIR: 1) a modernized grid that accommodates two-way flows of energy and energy services throughout the system; 2) a system that enables customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner; and 3) processes and mechanisms that animate opportunities for DERs to realize benefits.

To realize these goals, both the electrical power system and regulation will need to change rapidly to overcome barriers. The Final Guidance orders the utilities to identify three categories of barriers: (1) barriers to integration and interconnection; (2) barriers that limit the ability of DERs to provide benefits; and (3) barriers related to distribution system operational and infrastructure capability to enable DERs. Furthermore, the Final Guidance directs utilities to categorize the barriers as statutory, regulatory, grid insight, standards, safety, benefits monetization, or communications.[202] Overcoming these barriers will require change. As the Final Guidance states, "an inevitable consequence of these rapidly evolving changes to utility distribution will be the need to add new infrastructure, enhance existing networks and adopt new analytical tools."[203] SCE herein proposes general recommendations and grid modernization solutions to help overcome these barriers to deployment. SCE has divided the remainder of this chapter into three sections:

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[202] Note that some barriers are categorized as multiple types of barriers.

[203] DRP Ruling, p. 3.

- Section B identifies barriers to interconnection and integration of DERs into the distribution grid (Requirement No. 6a) and presents recommendations for overcoming these barriers.
- Section C identifies barriers that limit the ability of DERs to provide benefits (Requirement No. 6b) and potential ways to overcome these barriers and enable DERs to provide these benefits.
- Section D identifies barriers related to distribution system operations and infrastructure capability to enable DERs (Requirement No. 6c) and proposes recommendations related to actions and investments that may be needed.

Outside of the DRP, many other efforts are underway to identify barriers to DER deployment and to propose solutions.[204] These efforts include the views of regulatory agencies and third parties such as developers, researchers, non-profit organizations,[205] interest groups, and other organizations. In order to prevent duplicative efforts, and because SCE is not in the best position to characterize barriers experienced by third parties, SCE focuses on barriers to SCE's grid operations and SCE's customers in Chapter 6. To better consider the barriers experienced by third parties, SCE proposes to continue the process of identifying barriers with third parties and addressing these barriers through future DRP workshops after the DRP filing.

2. Executive Summary

To address barriers related to interconnection and integration, SCE has identified six key regulatory, grid insight, and safety barriers and made general recommendations and technology-

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204 For example, a recent example of this occurred on March 11-12, 2015, in which the Commission hosted a two-day Integrating Demand Side Resources workshop to, among other things, identify and prioritize barriers and propose solutions to barriers.

205 CAISO also developed the "California Energy Storage Roadmap" and the "California Vehicle-Grid Integration (VGI) Roadmap" to identify storage and electric vehicle barriers, respectively. Energy Storage: http://www.caiso.com/Documents/Advancing-MaximizingValueofEnergyStorageTechnology_CaliforniaRoadmap.pdf (page 3). CAISO's California Vehicle-Grid Integration (VGI) Roadmap, at p. 5 (February 2014). Available at: http://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf.

related recommendations. First, SCE is expecting a growing number of DER interconnection application requests and is in the process of developing a faster, streamlined, and more automated online application tool to meet these requests. Second, interconnection tariffs need to be modified to accommodate emerging technologies. Third, it may be challenging for an entire portfolio of DERs to be online and operating simultaneously to meet reliability needs because individual proposed projects often fail to be completed (due to permitting, interconnection, technology, or financing issues). Fourth, and as discussed in Chapter 5, first responders lack knowledge about the location and functionality of behind-the-meter DERs, which creates a safety issue. First responders should have information about DER equipment that may be at a home or building. SCE encourages the Commission to host a workshop with local authorities to establish an energy emergency database. Fifth, SCE notes that a prior Commission decision[206] required DG to provide physical assurance when acting as a distribution infrastructure alternative. SCE believes that there are multiple venues to ensure reliability, therefore, SCE requests that the Commission relieve SCE of this requirement. Finally, SCE notes that the regulatory process could be more flexible and quick to expedite all of the various practices that will be needed to support increased customer choice of new technologies and services.

To address barriers regarding the ability of a DER to provide benefits, SCE identified three key barriers related to regulation, benefits monetization, communication, and grid insight. First, today, certain DERs have a limited ability to participate directly in the wholesale market. Second, optimizing the ability of DERs to provide local reliability benefits may mean that DERs will need to be dispatchable. However, this raises many policy and jurisdictional issues that must be resolved, and SCE recommends these questions be discussed in future phases of the DRP OIR. Third, even after dispatchability questions are resolved, there is still a question of harmonizing DERs to meet

[206] D.03-02-068 in R.99-10-025 directs SCE to evaluate DG as an alternative to distribution upgrades.

local reliability and market needs. Sometimes, both market and reliability functions may be needed from DERs, and a priority protocol for how DERs should be dispatched needs to be developed.

SCE identified four barriers related to distribution system operations and infrastructure capability. First, the increased penetration of DERs might lead to poor voltage regulation, utility equipment overloads, and reliability concerns. SCE proposes deploying automated switches, remote fault indicators, and modern protection relays, as well as replacing existing conductors with larger conductors to provide telemetry to grid operators, enable two-way power flows, and increase DER hosting capacity. Second, grid operators have limited visibility into DER locations and impacts. SCE proposes developing a Grid and DER Management Tool, which would allow operators to evaluate the impact that DERs have on the grid, and grid analytics applications to allow grid operators to track customer performance. Third, SCE currently has limited ability to forecast system conditions and proposes to invest in long-term planning tools, distribution circuit modeling tools, and grid and DER management system. Finally, operational constraints prevent energy storage systems from drawing power off the grid during peak demand periods. SCE has proposed investments that, as laid out in the grid modernization chapter of the DRP, enable grid operators to increase their situational awareness and forecasting capabilities, combined with communication systems that enable grid operators to monitor, communicate, and enforce the operational constraints.

B. Barriers and Proposed Solutions Associated with the Interconnection and Integration of DERs to the Distribution Grid

The DRP Ruling identifies the need to "dramatically streamline and simplify"[207] the interconnection process and better integrate DERs into distribution planning, investments, and operations. To accomplish these goals, the DRP Ruling acknowledges the need to "add new infrastructure, enhance existing networks and adopt new analytical tools to allow consumers to be

[207] DRP Ruling, p. 3.

active managers of their electricity consumption through the adoption of DERs."[208] With that guidance in mind, this section examines the current interconnection processes under the Commission's jurisdiction, identifies barriers associated with integrating DERs, and proposes policy and technological changes to better integrate DERs. These changes include both policy-related changes that may be needed, as well as tools and technologies to automate and speed up processes.

1. Regulatory/Grid Insight Barrier: The Interconnection Request Process Should Be Revised to Handle the Growing Numbers of DER Interconnection Requests

Interconnection procedures, such as IOUs' current Rule 21, have at their foundation the need to ensure the safety and reliability of the grid. Rule 21 sets forth functions and equipment requirements for DERs that connect to the distribution system. The sheer volume and complexity of DERs seeking to interconnect to the distribution grid will continue to increase and may require refinements to Rule 21. In the last several years, the installation of distributed generation and energy storage resources in California has grown at a fast pace. In 2012, SCE processed 15,659 NEM applications, while in 2014, SCE processed 40,439 NEM applications – an annual growth rate of 79.12% per year. This volume is expected to continue growing at a high rate for 2015 and 2016, due to market anticipation of possible NEM tariff changes[209] and the reduction of the federal Investment Tax Credit (ITC) from 30% to 10% at the end of 2016.[210] SCE recognizes the need for additional automation and simplification and recommends the following improvements.

General Recommendations:

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208 *Id.*

209 PUC § 769 directed the Commission to develop a standard tariff or contract by December 31, 2015. The successor tariff will take effect either on July 1, 2017 or when the utility reaches its 5% program limit, whichever occurs first. Customers who sign up before the successor tariff takes effect will be grandfathered under the existing NEM tariff for 20 years.

210 The ITC will be reduced from 30% to 10% after December 31, 2016. http://energy.gov/savings/business-energy-investment-tax-credit-itc.

1) In Chapter 2,[211] SCE recommends that the modifications be considered within the Rule 21 OIR to consider efficiencies that could be included in the tariff because of the Commission-approved Integration Capacity Analysis (ICA). SCE has noted these potential efficiencies can modify Fast Track eligibility to more closely track available capacity on a circuit or streamline technical engineering screens because of the hosting capacity information provided by the ICA.[212]
2) SCE plans to develop a faster, streamlined, more automated Generation Interconnection Application Processing Tool for NEM, WDAT, and Rule 21 to meet the growing number of interconnection requests and to process and approve increasing numbers of interconnection applications in a timely manner, where appropriate. SCE performs interconnection studies to determine infrastructure upgrades needed to accommodate new DER projects in a safe and reliable manner and SCE plans to develop a Distribution Circuit Modeling Tool to enable engineers to quickly model various scenarios – ultimately speeding up the process of the technical review. SCE's DRP Data Sharing Portal will include an improved map to provide third parties with information about hosting capacity in SCE's service territory.

[211] Chapter 2, Section B.9 (Integration Capacity Analysis Use with Rule 21, Rule 15, and Rule 16)

[212] In Chapter 2, SCE recommended potential tariff language that can be incorporated into Rule 21. SCE also recommended that streamlining of Rule 21 be based on the fully studied 30 representative circuits; SCE will incorporate additional circuits as it expands the ICA to all circuits in the territory.

Summary of Recommended Technology Solutions (See Ch. 7 for Additional Information):

Ch. 7 Solution	Benefits
#10 Distribution Circuit Modeling Tool	• Reduces the technical review time for DER interconnection requests by allowing engineers to model different scenarios quickly and evaluate DER impacts on the grid.
#11 Generation Interconnection Application Processing Tool[213]	• Create an online application process, ultimately saving customers' time and enhancing the customer experience. • Speed up the review of interconnection applications (NEM, WDAT, and Rule 21) through a standardized, electronic process rather than manually, as is currently done.
#12 DRP Data Sharing Portal (Includes DERiM)	• SCE will create a map of hosting capacity within its service territory that will present developers, third parties, EV owners, and others with information about optimal locations where interconnection upgrades are less necessary, or where EV charging stations would have the fewest impacts on the distribution system.

2. Regulatory Barrier: Interconnection Tariffs Need to Accommodate Emerging Technologies

Existing EV rates and tariffs assume that EVs pull electricity from the grid and do not discharge electricity from the EV back to the grid. Generally, it is unclear how EV discharging electricity back to the grid would be treated from a billing and ratemaking standpoint. It is also unclear whether customers will be interested in using their EVs to supply power to the grid. There are currently no standard rates or tariffs that explicitly enable EVs to provide power to the grid. SCE is currently collaborating with the U.S. Department of Defense and the State of California on a V2G pilot, in which the EVs will draw power from the grid to charge their batteries and feed energy back into the grid in response to price signals from CAISO.[214]

Energy storage (ES) facilities that charge during off-peak hours and are available to discharge (generate) during peak hours provide value to the grid by serving peak demand. The mechanisms through which these devices can be interconnected are either in Rule 21 (CPUC-

213 Note that SCE is currently piloting a Generation Interconnection Application Tool on the sce.com website with Clean Power Research. SCE's grid modernization plan includes the development of a permanent tool that can help facilitate the processing of interconnection applications.

214 Additional information about SCE's DOD pilot can be found here: http://grid.lbl.gov/sites/all/files/lbnl-6154e.pdf. The pilot tariff for V2G is available at https://www.sce.com/NR/sc3/tm2/pdf/CE353.pdf

jurisdictional) or WDAT (FERC–jurisdictional) tariffs.[215] Often, the terms of existing interconnection agreements do not allow significant customization of device operation or implementation of the appropriate enforcement mechanisms without significant *pro forma* deviation processes through the appropriate regulatory bodies.

Another issue is how to make the operation of these projects more dynamic given the current contractual constraints. Current interconnection agreements are static, meaning operating requirements within them do not fluctuate to reflect grid needs that change hour by hour and year by year. Utility reviews are underway to assess whether interconnection agreement terms could be modified to address storage charging operational limits as a mitigation to costly system upgrades. Careful consideration must be given to the form of agreements to maximize the value of DERs to their owners and the grid.

The technical standards for V2G on both the automotive and grid side need to be addressed as the first step towards encouraging the streamlined interconnection and usage of V2G. On the grid side, generators that wish to seek interconnection using inverter-based technology need to be compliant with UL1741 and IEEE1547 standards for interconnection, in order to be eligible for evaluation via "fast track" methods. While the automotive industry does utilize various SAE[216] standards for V2G technology, these standards do not necessarily address many of the issues typically addressed by those standards such as UL1741 (like smart inverters) and IEEE 1547.

General Recommendations:

1) SCE recommends the development of a separate working group made up of both utility and automotive experts to work together to create a common standard acceptable to both industries so that V2G installations can be studied similarly to a UL1741-certified ES device.

[215] A storage device that charges off the system would not be using a fuel source that permits it QF status and thus its interconnection would be subject to FERC jurisdiction if it can export energy. A non-exporting storage device may interconnect under Rule 21.

[216] SAE International is a standards organization that develops automotive engineering standards, such as standards for electric vehicles.

2) As the number of V2G-capable EVs increase, SCE will recommend including different technical screens (developed through the aforementioned working group) to quickly assess the impacts of these EVs on the grid to process these applications on an expedited basis,[217] or will use the pro forma interconnection agreement (and/or appendices to such agreements) to address the unique characteristics of bidirectional V2G.
3) SCE supports more dynamic interconnection terms that account for operating characteristics and their related impact to the need for system upgrades. This proposal should be reviewed within the Rule 21 OIR.

3. Regulatory Barrier: Individual DER Project Failures Can Impact Portfolios of DERs

In the future, SCE envisions the possibility of utilizing portfolios of DERs, rather than a single DER project, as alternative providers of distribution infrastructure. For example, a solar PV project alone may not meet reliability needs that occur at night or on cloudy days. However, if the same solar PV project is paired with ES— either co-located, or at separate storage facility— it may help the utility maintain reliable electric service. When the utility is relying on a portfolio of DERs, these DERs must be online by the time the reliability or other need appears, and all the DERs in the portfolio must be capable of operating in concert to meet that reliability need.

It is possible that if multiple DERs are required to meet a need, that one or more of the DER projects within that portfolio may fail to be completed, and the remaining portfolio may not satisfy the grid need. Thus, the viability of DER portfolios successfully acting in concert to address reliability needs could depend on the success of individual projects.

[217] SCE has 12 technical FastTrack initial review screens that are intended to quickly assess whether the DER project would impact the grid. If the DER project passes all of the screens, then the project qualifies for Fast Track and no supplemental reviews or interconnection studies are needed. If the DER project does not pass the initial review and supplemental review screens, then the interconnection request is required to proceed with the detailed study process or withdraw.

General Recommendations:

1) In the short-term, SCE proposes to evaluate the viability of obtaining a DER portfolio to meet reliability needs in the DRP demonstration project (Demonstration C, described in Chapter 2).

2) In the long term, dependence on a single DER to meet a need as part of a portfolio could be resolved by contracting through a single vendor or aggregator to meet the entire need, rather than contracting piecemeal to meet the needs. The Commission and the parties should consider a way forward for a group of projects that can act as a joint entity.

4. Safety Barrier: First Responders Lack Information About DER Equipment Needed for Their Safety

In order for increasing levels of DERs to be safely integrated on the local distribution system, firefighters and other first responders will need better and more complete information about the locations and types of DERs. First responders to a fire-related emergency have no way to know whether a home or building contains DER equipment, much less what type of equipment is installed. Information regarding DER installations would help first responders isolate and quickly shut down the DER, as needed. Without the information, first responders, as well as the public are at risk if they accidently come into contact with an energized PV and/or storage system.

Likewise, inconsistencies among authorities having jurisdiction on allowable methods of DER interconnection causes unnecessary confusion and possible lapses in safety.

General Recommendations (See Chapter 5 Safety, Section E(1), for Additional Information):

1) SCE encourages the Commission to host a workshop with local authorities to discuss the possibility of establishing an energy emergency database (EED) for homeowners to self-register their PV and/or energy storage systems.

2) SCE will provide outreach to local permitting authorities on DER best practices via a future feature on SCE.com.

3) The CPUC, representatives of emergency responders, IOUs and stakeholders should work to develop uniform requirements relating to the interconnection of DERs across the state of California.

5. Regulatory Barrier: Prior Commission Decision Required DG to Provide Physical Assurance When Acting As an Alternative to Distribution Upgrades

On February 27, 2003, the CPUC issued D.03-02-068 in R.99-10-025 directing SCE to evaluate DG as an alternative to distribution upgrades. Thereafter, the Vote Solar Initiative (VSI) intervened in SCE's 2012 GRC,[218] disputing SCE's compliance with D.03-02-068 and Public Utilities Code Section 353.5, which require public utilities, including SCE, to consider DG in their distribution planning process (DPP) as an alternative to traditional distribution system upgrades. To resolve the dispute, SCE and VSI entered into a Settlement Agreement on September 1, 2011. The Commission approved the Settlement in D.12-11-051. Among other things, the Settlement Agreement required SCE, beginning in 2012, to conduct screening studies as part of its annual distribution planning process to determine if DG is a viable alternative for any planned distribution upgrades in certain localities and to launch a pilot Request for Proposal (RFP) during the 2012 GRC cycle to test the market for viable upgrade alternatives.

In compliance with the Settlement Agreement, SCE first identified potential areas where there might be viable alternatives to distribution upgrade projects. Thereafter, on June 13, 2014, SCE launched its Distributed Generation Solutions (DGS) Pilot RFP. The DGS Pilot RFP solicited proposals from customer-side DG in locations that would allow SCE to defer a project identified in SCE's DSP and scheduled for initial operation in 2017 by two years. Consistent with D.03-02-068, RFP bidders were asked to provide proposals that either gave physical load reduction assurance or eliminated the need for such assurance by combining multiple DERs to reach the target load reduction amount.

[218] *See* Application (A) 10-11-015, 2012 SCE GRC.

SCE received no viable proposals, which is not surprising given the physical load reduction assurance. While physical assurance is one way to ensure that the reliability of the distribution grid is maintained, it is unlikely that a reasonable commercial or industrial customer would be willing to have their facility disconnected from electric service during peak times (*i.e.*, summer months in the middle of the day), potentially with no notice (*e.g.*, if the generator were to unexpectedly go offline) and possibly for long periods of time (*e.g.,* if the generator was on a forced outage for maintenance). When local reliability and the deferral of distribution infrastructure depend on reliable DER performance, there may be other viable avenues for assuring local reliability without strictly requiring physical load reduction assurances. Thus, a more flexible approach should be adopted for achieving this important result.

General Recommendation:

SCE requests that the Commission relieve SCE of its current annual Distributed Generation Solutions (DGS) obligation associated with D.03-02-068. Given that the DGS is outdated, SCE recommends eliminating the obligation and, instead, allowing other activities, such as the RPS, Local Capacity Requirements (LCR), Preferred Resources Pilot, and DRP to inform how DERs and the grid can operate reliably in furtherance of the state's energy policy goals. SCE may, under certain circumstances, continue to require physical assurance - particularly in the case of a single, large generator that by itself may enable SCE to avoid or defer grid infrastructure. However, for larger portfolios of DERs, physical assurance may not be required.

6. Regulatory Barrier: Flexibility and Speedy Regulatory Approval Processes Needed to Design DER Deployment Strategies

SCE believes that modernization of the grid must be accomplanied by modernization of the regulatory processes. The Commission needs to create more flexible and faster processes for securing regulatory approvals in order to expedite all of the various practices that will need to be implemented to support increased customer choice of new technologies and services and higher DER penetration and usage. Such processes should include establishing a greater variety of templates and standardized agreements/forms, such as, for example, DER usage and deployment agreements (that could be developed in the future) and enabling shorter regulatory proceedings. This would, in turn, allow market enabling mechanisms to go into effect quickly and assure that administrative delays do not serve as a barrier to either customer choice or efficient DER market participation.

General Recommendation:

SCE recommends that, in order to facilitate the efficient deployment of DERs, the CPUC should create expedited regulatory processes, based on upfront standards and clearly identified objectives and development of template agreements where possible and appropriate. This would enable efficient, less expensive and more flexible interaction of customer choice and DER services.

C. Barriers and Proposed Solutions Regarding the Ability of DERs to Provide Benefits

The DRP Ruling stated that a goal of the DRP proceeding is to "animate opportunities for DERs to realize benefits through the provision of grid services."[219] This section discusses barriers that limit certain DERs from participating directly in the wholesale market, barriers that prevent DERs from providing local reliability benefits, and barriers that prevent DERs from being harmonized to both participate in the market and serve reliability needs. SCE also includes recommendations for how to overcome these regulatory and technology-related barriers.

1. Regulatory/Benefits Monetization Barrier: Certain DERs Are Limited in Their Ability to Participate Directly in the Wholesale Market

Compared to traditional large generation resources, many smaller DERs lack a clear path to the wholesale market, an issue documented in the Olivine Report.[220] For example, it is difficult for EVs (and other smaller DERs) to directly participate in the wholesale electricity market because the

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219 DRP Ruling, p. 3.

220 In 2014, the CAISO engaged Olivine, Inc. to provide a report documenting the challenges and barriers that exist for DERs to provide grid services (Olivine Report). The number one barrier that the report identified is the lack of revenue opportunity for DERs. http://www.caiso.com/Documents/OlivineReport_DistributedEnergyResourceChallenges_Barriers.pdf.

CAISO requires non-generating resources, such as EVs, to have a minimum of 500 kW capacity. This means that multiple vehicles must be aggregated to qualify as a non-generating resource that may participate in the wholesale market.[221] Similarly, current resource adequacy (RA) requirements lack criteria to determine if and how a demand-side resource (such as an EV) can count toward RA. In the future, it may be possible for aggregated EVs to provide value as flexible resources, which are defined as "generation resources whose operations can be directly controlled (are dispatchable) and quickly start up, shut down, and ramp power output up and down."[222] EVs can potentially be dispatched (or respond directly to price signals) to address system issues such as solar over-generation and ramping needs or provide local grid services such as ancillary services and demand response. For example, aggregated EVs at charging locations such as fleets, multi-unit dwellings, and workplaces could be significant in size and predictable in charging patterns. Since EVs may not be able to obtain QF status, any sales of power or ancillary services may subject them to FERC jurisdiction, which adds another layer of complexity.

For energy storage (ES), the utilities' customer-connected energy storage contracts perform as DR resources. In the future, it may be possible for customer-sited storage devices to provide additional CAISO market products, such as ancillary services. However, there are jurisdictional and operational barriers to optimization of customer-connected storage devices. In particular, the CAISO would need to develop new operational procedures to allow customer-connected projects to provide other market services. In addition, the sales of certain products from storage devices are likely to be FERC-jurisdictional rather than state-jurisdictional.

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221 Langton, Adam and Cristostomo, Noel, *CAISO Vehicle – Grid Integration Work Paper,* at p. 21 (October 2013), available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M080/K775/80775679.pdf.

222 CPUC Energy Division (February 2013) "Briefing Paper: A Review of Current Issues with Long-Term Resource Adequacy" (page 18).

http://www.cpuc.ca.gov/NR/rdonlyres/E2A36B6A-977E-4130-A83F-61E66C5FD059/0/CPUCBriefingPaperonLongTermResourceAdequacyBriefingPaperFebrua.pdf

Certain metering issues may prevent DERs from participating fully in the wholesale market. First, DERs interconnected to the distribution grid have a utility meter,[223] but if the customer would like to participate directly in CAISO's wholesale market, then the customer must also install a CAISO meter. However, this meter can be costly for customers with small DERs. Metering may be further complicated by the fact that customers may need to separately meter the energy drawn from the grid to serve its onsite load and the energy drawn from the grid to charge its storage device – where the stored energy may be resold. Energy used to charge the storage device (which the device will later resell) is purchased at the wholesale price, while energy used to serve onsite load is purchased at the retail price.

Sub-Load Aggregation Point (sub-LAP) boundaries, as defined today, are different from the local capacity area boundaries used by CAISO for determining resource adequacy. CAISO requires Non-Generating Resources (NGRs) to be located within the same sub-LAP and PDRs to be within the same sub-LAP and served by the same Load Serving Entity (LSE), while local capacity areas are used by LSEs for resource adequacy as well as for defining aggregator-managed DR contracts. These misaligned boundaries lead to a mismatch between CAISO requirements and LSE program requirements. This makes it very difficult for DERs, which may be located across boundaries in a certain local capacity area, to properly participate in CAISO's wholesale market. In addition, today it is difficult for DER aggregators to know whether their customers (or DERs) are located within the same sub-LAP because there is no clear method to get this information from the CAISO. As sub-LAP boundaries change over time, it could make a resource invalid and the resource could potentially lose its source of revenue.

General Recommendations:

223 Note that, currently, behind-the-meter DG greater than 1MW must provide metering and telemetry. In the future, smaller DERs that want to participate in the wholesale market may also need a CAISO meter in addition to the utility meter.

1) SCE generally supports the technical, market design, and regulatory observations contained within the Olivine Report[224] and encourages the Commission to consider endorsing and adopting these recommendations.
2) SCE recommends that the Commission work with the CAISO to encourage CAISO to provide venues for customer-sited storage devices and V2G-capable EVs to provide additional CAISO market products and work with other agencies and stakeholders on operational procedures.
3) SCE recommends that a new regulatory framework enabling aggregated EVs to flexible load (e.g., ramp-up, ramp-down, charge, shut-off) should be considered and developed with the CAISO and FERC.
4) SCE recommends that CAISO work with stakeholders to find a way to reduce the cost of purchasing and implementing CAISO meters and telemetry for smaller DERs. SCE generally supports the CAISO's ongoing initiatives, such as the "Expanded metering and telemetry options" initiative, which aims to reduce barriers for aggregated resource models.[225]

2. Regulatory/Communications Barrier: DERs Can Provide More Value If They Are More Dispatchable to Meet Reliability Needs

Today, some non-dispatchable[226] DERs provide value to the grid, but they would provide even more value if they were dispatchable. Other DERs are limited in their dispatchability, but they would be more valuable if they could remove some of their limitations. For example, solar inverters can change the power factor at the point of interconnection to meet voltage and/or reactive power

[224] To help overcome the barrier related to a lack of revenue mechanisms, the Olivine report made five recommendations, including a reference to SCE's all-source procurement and Preferred Resources Pilot, developing a forward capacity procurement framework, enable DER to participate in RA contracts, define the must-offer obligation for DERs and other resources, and consider a multi-year competitive auction mechanism for aggregated DERs.

[225] Additional information about this CAISO initiative can be found at: https://www.caiso.com/informed/Pages/StakeholderProcesses/ExpandingMetering-TelemetryOptions.aspx

[226] Most non-wholesale DERs are not "dispatchable" for reliability purposes (*e.g.,* EE, customer-side DG, EVs, and customer-side energy storage systems are not dispatchable).

needs. To maximize the reliability benefits of DERs, system operators may need the ability to dispatch these resources to meet changing grid needs.

DR is dispatchable, but its dispatchability is limited by the maximum frequency and duration of DR events that customers volunteer to participate in each year. To maintain voluntary customer participation in DR, customers must value the financial incentive paid under the DR program more than the cost of the resulting interruptions and behavioral changes they must undertake. As such, DR programs must balance the frequency and duration of DR dispatch events to enable the DR resource to provide adequate grid reliability benefits without creating customer fatigue and reducing customer participation in DR.

In the future, if certain DERs are to maximize their reliability functions, then these DERs may need to be dispatchable for reliability. However, there are many overarching policy questions related to dispatchability. There is a lack of clarity around which entity (or entities) would schedule the DERs, dispatch the DERs, and enforce the dispatch instructions. Dispatchability would also require new technological solutions. SCE is currently the provider of local grid reliability and plans to integrate DERs. SCE's proposed investments in the grid, DER management tools and communications network would allow grid operators to forecast, track, and send dispatch signals to DERs. For both EV charging and storage, more pilots are needed to better understand the complexities, costs, and trade-offs involved in addressing both system-wide and local grid needs.

General Recommendations:

1) In Chapter 8, SCE recommends that the DRP OIR focus on policy issues in subsequent cycles of the DRP. Policy questions related to dispatch should be considered in the context of distribution system markets in Phase 2b.
2) Dispatchability questions associated with program limitations related to specific DERs and pilots for storage, EV charging, and other DERs (*e.g.,* DR programs) should be taken up in the appropriate proceeding (*e.g.,* DR OIR).

Summary of Recommended Technology Solutions (See Ch. 7 for Additional Information):

Ch. 7 Solution	Benefits
#13 Grid and DER Management Tool	• Enables operators to forecast, track, and interact with DERs. This allows operators to be more aware of the actual dispatchable resources available at a particular location.

3. Grid Insight Barrier: DERs Will Need to Be Harmonized to Meet Market and Local Reliability Needs

The previous barrier discussed the dispatchability of DERs as a barrier; however, even if DERs are dispatchable, there needs to be a clear indicator of how DERs will be harmonized to meet market and local reliability needs. For DERs to serve as a local distribution grid reliability resource, DERs must have an ability to respond to local reliability needs. Currently, some customer-connected and distribution-connected storage devices may respond to wholesale market price signals – however, these market signals may not reflect local distribution system needs. This is because the wholesale market price signals reflect larger system constraints (including system peaks), but local distribution systems may have different constraints (including non-coincident peaks). If a storage device is discharging energy to the system peak in response to a higher wholesale price, but the system peak is not coincident with the local peak, then the storage system might counterproductively discharge when there is no local need, and charge when local needs peak. Therefore, one key barrier that limits the ability of energy storage systems to provide local reliability benefits is that the wholesale price signals do not reflect distribution system conditions.[227] The utility may need reliability services from DERs to help meet reliability needs. Other DERs, such as DG, EVs, and DR will also need the ability to respond to more localized reliability needs.

The long-term effectiveness of DR can be improved if DR can be consistently dispatched at more granular levels. DR programs are dispatched at different levels on the electric system – some

[227] In the future, grid operators may need to override market-functioning storage systems for local reliability functions, however, there is no existing process to switch control from one function to the other.

DR programs can only be dispatched across the entire system, while other DR programs can be dispatched at the substation level.[228] In the future, DR programs may need to be modified to provide even more granular local reliability benefits (such as, at the neighborhood-level or groups of customers on particular circuits). One benefit of this is that it helps reduce "DR fatigue" – customers opting out of DR programs because DR events have been triggered too many times – because fewer customers will be triggered to address reliability events at one time. Technical and programmatic modifications to existing infrastructure would have to be made to enable this more targeted functionality. SCE's proposed Grid and DER Management System, which would enable operators to be aware of and potentially dispatch local DERs, and the Field Area Network, which would allow the operators to broadcast a local reliability signal to trigger local DERs, would help build the capabilities required to have this more targeted functionality.

DR resources can be activated to address both distribution grid reliability needs and broader bulk power market functions. This leads to potential scenarios where a DR program can be activated for a wholesale market need – but the local reliability need may differ from the wholesale market need. Therefore, DR programs must be harmonized to meet multiple objectives (*e.g.*, perhaps local grid reliability functions can override wholesale market functions, if both functions are needed at the same time) so grid operators can dependably utilize DR as a resource to meet both global and local reliability needs.

SCE's grid modernization investments will include a Grid and DER Management System, which can help operators understand how much of a DER is actually available and to be able to dispatch the resource to meet reliability needs. For example, if a summer peaking substation is projected to exceed thermal limits by 2MW, the local distribution system operator would know which energy storage had been previously utilized for market needs and if 2MW of local energy storage was available for reliability dispatch. This is similar to CAISO knowing the level of spinning

[228] For example, grid operators can trigger a DR event that affects DR customers near a specific substation; all other DR customers across the system would not be affected.

and non-spinning reserves currently available for dispatch at any moment. The operator could then dispatch the energy storage at a time to meet the need.

General Recommendation:

SCE recommends that the Commission consider harmonizing DERs to meet distribution grid reliability needs and market functions in the applicable proceedings (*e.g.*, DR OIR). As SCE described above, sometimes both the bulk power market and local reliability functions are needed, and the Commission must establish a priority protocol for how the DERs should be utilized.

Summary of Recommended Technology Solutions (See Ch. 7 for Additional Information):

Ch. 7 Solution	Benefits
#13 Grid and DER Management System	• Operators would be more aware of DERs on the grid, while monitoring and forecasting the overall situation on the grid. This allows operators to be aware of the DERs that may be able to help support reliability when there is a local need and provides the ability to dispatch DERs at the appropriate time and level of granularity.
#5 Field Area Network	• SCE can broadcast a local reliability distress signal using the field area network. DERs within the area (which may be owned by customers, third party aggregators, or utilities) can potentially receive this signal and activate a DER to provide grid reliability benefits.

D. Barriers and Proposed Solutions Related to Distribution System Operational and Infrastructure Capability to Enable DER Provided Value

For DER usage and penetration to be fully developed, the existing infrastructure must evolve to not only allow DERs to interconnect safely and reliably, but also to enable opportunities to make DER multi-use and monetize their benefits. As explained in SCE's Grid Modernization chapter (Chapter 7), improvements to the distribution grid will address these barriers by enhancing the capability to forecast, monitor, track, and use DERs through distribution system investments. This will ultimately facilitate and enable DERs.

1. Safety Barrier: High Penetration of DERs May Lead to Poor Voltage Regulation, Utility Equipment Overloads, and Reliability Concerns.

The distribution system is "radial." This means there is one circuit intended to transport power in one direction from the distribution grid to the home or business (load). High penetration levels of DERs that cause bidirectional power flows could lead to a host of reliability and safety issues, including voltage fluctuations; power quality, protection, and thermal issues; and current and voltage imbalance. These safety issues are discussed in more detail in Chapter 5.

SCE's older distribution protection equipment was designed to operate in one direction and without the ability to distinguish fault current from load current or what SCE calls "load encroachment." Increased load or generation could cause the protective relay to malfunction if the magnitude of the load or generation encroaches upon the preset value or "Phase Minimum Trip." In addition, older distribution protective relays have no directional element and therefore cannot sense fault conditions in multiple directions. This could cause malfunction of the protective relay. In some locations, adding DERs can create challenges for protection of longer circuits since the generation makes it harder to detect faults at the ends of the circuit. Older protection equipment was designed for fault conditions that result from surges of current from the grid to the fault location. With high penetration of DERs, this surge of current from the grid could be reduced to where some protection systems are desensitized to faulted conditions. This scenario would directly pose a risk to public safety.

Grid assets are sized to meet the expected load for a given location on the grid. As long as the amount of load does not exceed grid asset equipment ratings, energy can be provided through that equipment without reducing its life expectancy. Large or aggregated DERs can produce power flows that exceed the planned loading limits of grid assets resulting in thermal overload, which reduces life expectancy of the grid asset. Therefore, grid "reinforcement" investments (described in more detail in Chapter 7), such as replacing existing conductors with larger conductors, will be needed to accommodate larger amounts of load.

Summary of Recommended Technology Solutions (See Ch. 7 for Additional Information):

Ch. 7 Solutions	Benefits
#1 Automated Switches w/ Enhanced Telemetry #2 Remote Fault Indicators	• Allows grid operators to track what is happening on the distribution grid and quickly respond to outages and other power issues. • Provides additional telemetry at strategic points in the distribution system and allows operators to better locate causes of system outages.
#4 Modern Protection Relays	• Enables two way-flows by allowing power to back-feed from one part of the distribution system, through the substation, and out towards other parts of the distribution system.
#16 Conductor Upgrades	• Replacing existing conductors with larger conductors that will accommodate larger amounts of load.

2. Regulatory/Grid Insight Barrier: Limited Visibility of DER Locations and Impacts

Distribution system planners lack visibility regarding certain energy efficiency, demand response, and DG installations. This lack of visibility applies to both their specific location and real-time status. Today, a grid operator's real-time visibility into DG installations is limited to installations greater than 1 MW.[229] Below one MW, system operators cannot see or forecast the outputs of DERs to make decisions in response to outages or necessary system reconfigurations. This forces operators to make assumptions when responding to changing system conditions. These assumptions have historically been relatively accurate for simple distribution systems configurations where the flow of power is in a single direction and predictable. However, with increased penetration of DERs, it will be increasingly difficult to make accurate assumptions about power flows below substations. SCE has proposed technology and software solutions, such as the Grid and DER Management System. This system can help resolve this issue by improving situational awareness for grid operators and by facilitating the evaluation of DER impacts on the grid.

There are three barriers that limit SCE's ability to accurately plan and account for EE in addressing distribution needs. These barriers include: (1) a lack of visibility into the location of some EE installations; (2) a lack of understanding of the full grid impacts of EE installations; and, (3) the impact of customer behavior on actual EE savings.

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229 DG systems larger than 1MW require telemetry.

First, SCE’s upstream and midstream EE programs provide incentives to manufacturers, distributors, and retailers, which in turn, sell EE equipment directly to customers at a reduced price. Since customers do not have to fill out a rebate application at the point of sale, SCE does not have visibility into the location on the distribution grid of the equipment installation.

Second, California IOUs are largely required to measure, incent, and report those energy savings from EE equipment upgrades that exceed the requirements of existing building codes and appliance efficiency standards. To the extent that existing equipment is not at existing code levels, this approach does not consider the energy savings that are realized in bringing existing equipment up to code levels. Therefore, SCE’s measured and reported EE savings may undervalue the full impacts that EE installations provide to the distribution grid, as the distribution grid will realize the entirety of savings from the retrofit project. Gaining a more accurate understanding of the total grid-level savings resulting from EE installations--not just those savings measured above applicable codes and standards--would enable SCE’s distribution planners to better assess the true value of EE installations to the distribution grid.

Third, customer behavior will also have an impact on the load impacts that we expect to see on the distribution grid. Customer behavior, occupancy changes, building modifications, and other factors may, over time, affect a customer’s energy consumption and augment or detract from the savings provided by EE installations.

Obtaining a greater understanding of the location and magnitude of EE savings impacts on the distribution grid will also benefit efforts to improve the granularity of EE forecasting. Today, the Commission issues a study that identifies forward-looking EE market potential, which guides the development of goals for EE that the Commission establishes for each IOU. The study provides information on estimated EE potential in each IOU’s service territory, disaggregated by customer segment and climate zone. The study does not disaggregate this potential based on any type of distribution grid planning or localized geographic area.[230] Creating projections based on locations could be valuable in better forecasting the future hosting capacity of a localized area of the grid, which could, in turn, be used to inform local distribution system planning. SCE's proposed Grid Analytics Applications and Long Term Planning Tool Set could improve the accuracy, reliability, and granularity of the DER potential by forecasting from the "bottom-up" (at the customer level) and including up-to-date information about the location of DERs that are currently deployed on the grid.

General Recommendation:

The Commission should work collaboratively with the CEC, CAISO and the utilities to develop a framework for conducting accurate potential studies for EE (and other DERs) at more localized levels to inform future DRP submittals and align forecasts with other DER proceedings. As the EE potential study is developed through the EE OIR, this effort could be taken up in that proceeding. To the extent that other DER potential studies are developed in other proceedings, SCE suggests this similar collaborative framework be utilized to better understand how to incorporate locational insights.

[230] Note that some EE potential and saturation studies utilized by the CPUC and CEC to inform EE forecasts are conducted at the climate zone level of geography.

Summary of Recommended Technology Solutions (See Ch. 7 for Additional Information):

Ch. 7 Solution	Benefits
#1 Automated Switches w/ Enhanced Telemetry	• Provides telemetry at circuit points on the distribution grid, tracking the impact of DERs.
#3 Upgrade Substation Automation Schemes	• Provides telemetry at the substation level and tracks the impact of DERs.
#5 Field Area Network #6 Fiber Optic Network	• Enhances operator situational awareness by sending data to operators • Enables data to be transferred in real-time, safely and securely.
#8 Grid Analytics Applications #9 Long-Term Planning Tool Set	• Allows increased use of smart meter data to determine effectiveness of various EE and DR measures • Allows for more accurate EE and DR forecasting as part of the distribution planning process
#13 Grid and DER Management Tool #14 Systems Architecture & Cybersecurity	• Allows operators to evaluate the impact that some DERs are having on the grid • Safely and securely monitors the grid and looks for issues from distribution automation and substation automation; and compares data to the rest of the system

3. Grid Insights Barrier: Limited Ability to Forecast System Conditions

Electric utilities have observed and monitored customer demand for electricity over many years and have predicted customer demand with relatively high accuracy. Customer usage as a function of time for a customer class (*e.g.*, residential, commercial, industrial, agricultural) has, until now, followed predictable load patterns. As increased levels of DERs are realized on the distribution grid, these load patterns of a distribution feeder will become less and less predictable.

As the penetration of DERs exerts an increasing influence on load patterns, real-time data of DER performance becomes more critical in long-term planning. However, there are currently no requirements to provide this performance data to the utility. Instead, system planners use engineering judgment and extrapolate other real-time data sets to estimate DER performance and impacts on circuit load profiles. Catastrophic equipment failures can result from inaccurate assumptions, so engineers adopt more cautious assessments that tend to introduce economic inefficiencies in system design. SCE's proposed long-term planning and distribution circuit modeling tools would enable planners to incorporate DERs into long-term planning by gathering actual DER performance data (gathered through the grid and DER management systems) and extrapolating future performance.

Summary of Recommended Technology Solutions (See Ch. 7 for Additional Information):

Ch. 7 Solution	Benefits
#9 Long Term Planning Tool Set	• Allows planners to incorporate DERs into long-term planning
#10 Distribution Circuit Modeling Tool	• Allows engineers to model distribution circuits from days to months to forecast power flows
#13 Grid and DER Management System	• Monitors the grid and makes near-term estimates of grid needs and DER resources to help forecast system conditions from a few minutes to a few days • Improves situational awareness for grid operators

4. Communications/Standards Barrier: Operational Constraints Must Be Monitored, Communicated, and Enforced to Help Meet Local System Needs

SCE accommodates new DERs on the grid through system upgrades. These upgrades allow DERs to produce energy at the interconnection location during peak times without causing equipment overloads or other impacts to the system. However, to ensure grid reliability, particularly during peak, as DER penetration increases, it may be necessary to exert at least a minimum level of control over some DERs. System disturbances can cause portions of the system to be unavailable affecting the balance of consumption and production at the feeder and substation level. In addition, the changing profiles of demand and generation can cause voltage swings based on the location and characteristics of individual performance. These types of changes can happen instantaneously and can have significant impacts to the reliability and quality of power that customers experience.

As maintenance outages and other events require a continuous modification to the power flows on the distribution grid, SCE must coordinate these changes with DR programs to ensure the most effective dispatch of DR resources to the right places on the grid. This requires a dynamic way to maintain alignment between DR programs, customer enrollment, and grid operations, in consideration of changing grid configurations.

Energy storage systems may also impose a reliability risk on the system because they can draw power from the grid during peak demand periods. Two methods for promoting reliability are to: 1) impose operational restrictions that prevent the ES facility from drawing power off the grid during peak demand periods and 2) build system upgrades to remove the constraint. Customers employing ES systems should be able to structure their interconnection agreements to either accept operational constraints (*i.e.*, restricted charging during peak conditions) or pay for system upgrades if the unlimited operation of the ES system can cause reliability issues.[231] In Section B(2) of this chapter, SCE discussed the need for dynamic interconnection agreements. However, even if interconnection agreements can include dynamic operational constraints, it is unclear how these constraints would be monitored, communicated, and enforced. There are currently no standards, rules, or deployed technology for distribution system operators to monitor operations, communicate commands, and enforce the constraints.

General Recommendation:

SCE recommends that the Commission consider developing requirements that would allow distribution grid operations to maintain visibility to energy produced by certain DERs, and if needed, to dispatch the DERs for grid reliability. This may require the development of industry standards that enable the safe dispatch of distributed generation systems to meet the needs of distribution grid operations. Such industry communications standards do not currently exist today.

Summary of Recommended Technology Solutions (See Ch. 7 for Additional Information):

Ch. 7 Solution	Benefits
#1 Automated Switches w/ Enhanced Telemetry #2 Remote Fault Indicators #3 Upgrade Substation Automation Schemes #13 Grid and DER Management System	• Collectively, these investments provide grid operators with enhanced situational awareness and allow operators to track real-time operations throughout the distribution network • Operators will be able to quickly identify issues in the grid and dispatch responses, ultimately resulting in increased reliability for customers
#5 Field Area Network	• Enables grid operators to send a signal to communicate local reliability needs

231 Customers may need to pay for system upgrades that assume that the energy storage system is charging during peak hours.

Chapter 7:
SCE's Grid Modernization Investments

VII.

CHAPTER 7: SCE'S GRID MODERNIZATION INVESTMENTS

A. Introduction and Executive Summary

SCE's DRP is intended to serve as a foundation for the evolution of the grid that will serve important state goals such as reducing GHG emissions, accommodating two-way energy flows, enabling greater customer choice in new technologies and services, and creating new opportunities for DERs to provide benefits to the grid.[232] To accomplish these ambitious and transformative goals, and as PUC Section 769 envisions, SCE has submitted a DRP "that recognize[s], among other things, the need for investment to integrate cost-effective DERs,"[233] including investment "to add new infrastructure, enhance existing networks and adopt new analytical tools."[234]

In this chapter, SCE identifies grid modernization investments that SCE believes will help to implement Section 769 and the goals articulated in the DRP Ruling by building a 21st century power system capable of supporting a future of distributed technologies. A modernized grid can integrate a variety of different technologies and enable DER portfolios to provide a variety of grid services that support California's policy goals and meet customers' expectations. To create this new grid, SCE is proposing to increase its investments in modernization technology and grid capacity. Grid modernization is intended, through a set of targeted investments, to facilitate DER integration by: (1) expediting interconnection processing, (2) creating increased operator situational awareness, (3) enabling more accurate forecasting and planning, and (4) creating greater interaction between the grid and DER operations.

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232 DRP Ruling, pp. 2-4.

233 DRP Ruling, p.2.

234 DRP Ruling, p. 3.

In addition to modernization, a complementary set of investments will be needed to increase grid capacity to support increased levels of DERs. These "grid reinforcement" investments include upgrading conductors to a larger size and increasing circuit voltage to support increased DER penetration. SCE is proposing grid reinforcement to mitigate the reliability impacts of higher DER penetration, such as those described in Section D.5 of Chapter 2 (DER Growth Scenarios Impact on Distribution Planning). SCE's vision is that investments in foundational technology—such as investments in grid modernization and grid reinforcement—will support higher DER penetration, provide more customer choice over new technologies and services, create additional operational opportunities for DERs, and support the Commission's recommendations for a phasing as outlined in 9.b of the Final Guidance.

With all this in mind, SCE hereby requests permission to file a Tier 1 Advice Letter establishing a Distributed Energy Resources Memorandum Account (DERMA), which would track spending on grid modernization and grid reinforcement that SCE may incur prior to its next GRC.[235] SCE seeks this authority to allow SCE the opportunity to recover the incremental revenue requirement associated with 2015, 2016 and 2017 capital expenditures and operations and maintenance (O&M) expenses by including these costs for review and cost recovery authorization in SCE's 2018 GRC.

The Final Guidance directed SCE and other utilities to include a "section in their DRPs where they describe what specific actions or investments may be included in their next GRCs as a result of the DRP process."[236] In this chapter, SCE identifies investments intended to integrate DERs into its planning and operations in support of the DRP goals and future proposed phases. Section B(1) provides an overview of the two types of investments

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235 SCE will only seek recovery of incremental revenue requirement to the extent it exceeds the amounts authorized in the 2015 GRC final decision. SCE will examine recorded investments and expenses compared to authorized levels and then file for cost recovery of the incremental revenue requirement. This approach is consistent with California Public Utilities Code Section 769(d), which contemplates recovery of the DRP costs through the GRC process.

236 Final Guidance, p. 11.

necessary for a 21st century, “plug-and-play” electric system, namely, grid modernization and grid reinforcement. Section B(2) details four critical grid capabilities that need to be improved to successfully integrate DERs into planning and operations processes and identifies specific, near-term grid modernization investments that are necessary to begin to develop these capabilities. In Section B(3), SCE describes a set of grid reinforcement investments that complement grid modernization and increase the capacity of the distribution grid to accommodate higher penetration of DERs. Section C recommends establishing a tracking account (the DERMA) to enable necessary near-term investments, which can then be included as part of SCE’s next GRC.

B. Description of Investment Categories

1. Overview

Grid modernization is not a new concept. Utilities have been making proactive investments to modernize existing infrastructure since the inception of the grid, including more recent investments directly related to DER growth. What distinguishes SCE’s DRP investment proposal from prior efforts is its focus on incorporating DERs into utility distribution planning and operations to improve system efficiency.

In addition to safely and reliably integrating more DERs, grid investments proposed by SCE will enable SCE to develop new tools and methodologies to analyze the integration of DERs at a more granular level. These investments will also provide the next generation of substation and distribution circuit automation.

SCE’s grid investment plan was developed to implement a proactive, coordinated two-pronged approach to the deployment of information technology, automation, and distribution grid reinforcements. These deployments are designed, over the next 10 to 15 years, to achieve the 21st century power grid.[237]

[237] Due to the relative size of SCE's system, SCE will begin modernizing the grid in urbanized areas and other locations where there are benefits and organic growth of DERs. Most of these

(*Continued*)

The first prong of this approach, "grid modernization," includes investment in information technology (IT) and automation focused on better monitoring and control capabilities. The initial set of investments is aimed at providing enhanced system-wide planning tools to support the DRP and grid analytics capabilities that leverage grid data to improve operating efficiency, such as leveraging smart meter data to identify potential grid performance problems. IT investments also consist of enhanced communications and control capabilities to provide grid operators increased ability to operate a more complex grid and interact with DERs. These IT investments will be combined with enhanced circuit and substation automation. The purpose of automation technologies is to improve protection, real time data acquisition, and flexibility. Examples include remote fault indicators (sensors) to provide more information about grid status and remote intelligent switches to improve isolation and operations.

The second prong of SCE's investment plan focuses on "grid reinforcement," which includes investment in conductor upgrades and accelerating the conversion from 4 kV distribution voltage to 12 kV or 16 kV. These investments are focused on increasing grid capacity for integration of DERs through upgrades to grid infrastructure where needed. Conductor upgrades will be coordinated with enhanced circuit automation to provide for more robust circuits with increased granularity of control. The acceleration of 4 kV elimination projects will be targeted such that the projects can accomplish the dual objective of replacing aging infrastructure as well as providing for organic growth of DERs. These investments are critical because 4 kV circuits have a very limited capacity for integrating DERs (as shown in Chapter 2, Section B.5) and they serve many of the areas

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modernization efforts are anticipated to be completed in the 10 to 15-year timeframe, but other efforts will continue beyond this timeframe.

where residential and small commercial customers are likely to adopt rooftop solar and other types of DERs. SCE currently has 957 4 kV (and 4.8 kV) circuits which altogether serve 639,474 customers, or approximately 13% of SCE's total customer base. The 4 kV elimination projects are already identified, and some can be accelerated.

In putting together its proposed investment plan, SCE has developed a prioritization methodology to determine where initial IT, automation, conductor upgrade, and 4 kV elimination investments should be targeted. The methodology is focused on areas where SCE believes investments can achieve the most immediate system benefits and incorporates several factors from SCE's existing distribution and transmission planning processes such as: where DERs can offset forecasted demand to potentially reduce the need for future transmission investment; where DERs can potentially reduce the need for identified future distribution substation upgrade and circuit addition projects; and where DERs can potentially reduce forecasted demand in areas of high capacity utilization.

For IT and automation, the focus will be on technology aimed at speeding up interconnection and enrollment for interconnection customers, providing grid operators with increased situational awareness to improve reliability and safety, enhancing forecasting and planning capabilities to incorporate DERs, and enabling greater interaction with and control to enable DERs to provide a greater range of services. For grid reinforcement, investments in infrastructure replacements and upgrades, such as upgrading conductors and conversion from 4 kV to a higher circuit voltage (so that the grid can reliably accommodate more DERs) will be targeted in locations, as noted above, where DERs have opportunities to provide grid benefit such as helping to meet new load growth.[238] To manage overall costs, the proposed

[238] Load growth projects are system upgrades that are required to meet forecasted system needs per SCE's system planning criteria. Some examples of load growth projects are new distribution circuits, transformer additions at substations, or sub-transmission conductor upgrades. Load growth projects are described in detail in SCE's 2015 GRC. *See* A.13-11-003, SCE's 2015 General Rate Case, Exhibit SCE-03, Vol. 3.

grid investments will be strategically aligned, as much as possible, with previously planned replacements and upgrades of substation and distribution automation, infrastructure replacement, and existing information technology and communications infrastructure.

a) Grid Modernization

Grid modernization investments include the deployment of innovative new technologies in distribution automation, substation automation, communications systems, and technology platforms and applications. Deploying these technologies in targeted areas that are forecast to experience higher levels of DER penetration and where grid expansion projects have been planned will deliver the most customer benefit. In its near-term investment plan, SCE proposes prioritizing modernization in areas where DERs can provide system-level transmission benefits, including locations where DERs may be able to decrease peak demand, thereby avoiding the need for certain new transmission infrastructure,[239] and have the opportunity to defer traditional distribution upgrades, such as capacity upgrades at distribution substations and new distribution circuits.

The Johanna Jr. substation, located in Santa Ana, has been identified for demonstration and deployment activities in Chapter 2 of this DRP and is an example of this analysis. Johanna Jr. has a distribution upgrade planned for 2023 and is located in an area where a decrease in demand due to DERs can provide benefit to the transmission system.

Increased levels of substation and distribution automation will result in more data, such as voltage, current, and power flow at substations and along the distribution circuits. Such automation will also provide remote control of devices within the substation and more precise switching operations throughout distribution circuits. This will support increased levels of DERs by providing more information to operators regarding system performance and the effect of DERs on the grid. This will also give operators more flexibility to remotely

[239] Grid modernization will happen over many years and the resulting benefits will be demonstrated over a period of time.

operate the system and increase the ability of DERs to provide grid benefits, such as meeting peak demand and supporting voltage and reactive power needs. As part of substation automation, modern protection relays combined with high-speed communication will be installed to enable bi-directional load flows using more complex protection schemes.

Advances in communications and control systems will be needed to support the increased levels of automation as well as the increased levels of DERs. A large amount of data such as voltage, current, and power flow will be generated by the new automated devices as well as the DERs themselves. This data must be transmitted securely to operators in real-time so that operators can evaluate and react quickly to mitigate problems if they arise. In addition, new technology platforms and applications will enhance analytics and modeling capabilities for planners to evaluate the capability of DERs to meet reliability functions as well as develop statistical models necessary to improve load forecasting.

b) Grid Reinforcement

Grid reinforcement investments are enhancements to the distribution system intended to increase the grid's ability to support more DERs. When high levels of DERs are interconnected near the end of distribution circuits, the system may operate outside of thermal, voltage, and protection limits, contributing to potential public and worker safety risks. Strategic upgrades, including reconductoring of mainline circuitry, working in conjunction with SCE's efforts to eliminate small conductors to support public safety, and converting circuits to higher voltage in conjunction with aging infrastructure improvements mitigate these issues. These types of investments will support a "plug-and-play" distribution system and enable customer choice of new technologies and services.

Larger conductors can increase thermal capacity of distribution circuits to accommodate DERs and mitigate scenarios where the voltage exceeds operating limits. The integration capacity analysis will give SCE a set of tools to evaluate locations where mainline conductors can be upgraded to increase their capacity for accommodating DERs. Furthermore, as discussed in SCE's integration capacity analysis in Chapter 2, the voltage class of a particular distribution circuit can limit the amount of load and DERs that can be interconnected due to increased losses and inefficient design to support high penetration of DERs. SCE has been undertaking a longer-term program to eliminate most of the aging 4kV portion of its system, rather than investing in the replacement and upgrades at this voltage level.[240] Accelerating this conversion from lower voltage distribution circuits to higher voltage circuits will support increased amounts of DERs.

Beginning in 2015 and over the course of SCE's proposed grid investment program, grid reinforcement upgrades will be targeted to areas where high numbers of DERs are anticipated to provide system benefits. This grid reinforcement is needed to enable DER penetration to occur, so that DERs potentially can serve as alternatives to traditional capital upgrades to meet load needs. The scenario analysis in Chapter 2 highlighted some examples where forecasted levels of DERs exceeded integration capacity, thereby requiring upgrades to the approximately ten percent of distribution circuits where such constraints exist. Making such upgrades in areas where DERs are forecasted to grow significantly will result in a more robust grid, facilitating easier interconnection of new DERs.

2. Grid Modernization Investment Plan: Enabling DER Interconnection, Integration, and Services

SCE has identified four future grid modernization capabilities that will be required to successfully integrate DERs into planning and operations of a modern grid: (1) expedient interconnection processing; (2) operator situational awareness; (3) accurate forecasting and planning; and (4) greater interaction with, and control over, DER operations.

First, to support increased levels of DERs, SCE must process interconnection applications more expeditiously. As discussed in Chapter 6, the installation of DERs in California has grown at a very fast pace; for example, in 2012, SCE processed 15,659 NEM

[240] SCE's current plan to eliminate 4kV systems is described in detail in SCE's 2015 GRC. *See* from A.13-11-003, SCE's 2015 General Rate Case, Exhibit SCE-03, Vol. 4.

applications, and in 2014, SCE processed 40,439 NEM applications – an annual growth rate of 79.12 percent. To keep up with this anticipated growth of rooftop solar as well as other DERs such as energy storage, SCE will automate its interconnection process, which will provide faster processing of applications, clearer identification of technical data needed to perform impact evaluations, and up-to-date tracking of progress.

Second, to support increased levels of DERs, increased operator situational awareness is needed. To maintain a safe and reliable grid, the utility must have access to more granular levels of data and remote operation capabilities throughout the distribution system. It will be necessary to collect more frequent data at a variety of points on the grid in order to understand grid conditions and asset performance. This is true for both real-time operations and long-term system planning. Current practices of real-time monitoring must expand beyond the substation circuit breaker to strategic locations along the distribution feeder, including isolation points and locations where radial lines[241] extend from the main line. Increased situational awareness will allow operators to detect abnormal asset performance or grid conditions that could lead to safety or reliability impacts. Real-time visibility will provide the utility with pertinent information to assess outages and restore service for customers faster than previously possible.

A third capability needed to support higher penetration of DERs is accurate forecasting and planning. SCE's system planners will have to develop effective, long-term solutions to meet changing grid conditions. Planning tools that incorporate higher levels of granular data, such as telemetry along the distribution circuit and smart meter data, are widely recognized as fundamental to the evolution of the planning process in a more complex environment. For example, if a given distribution substation or circuit contains high levels of solar PV, energy storage, and electric vehicles, consumption and production of

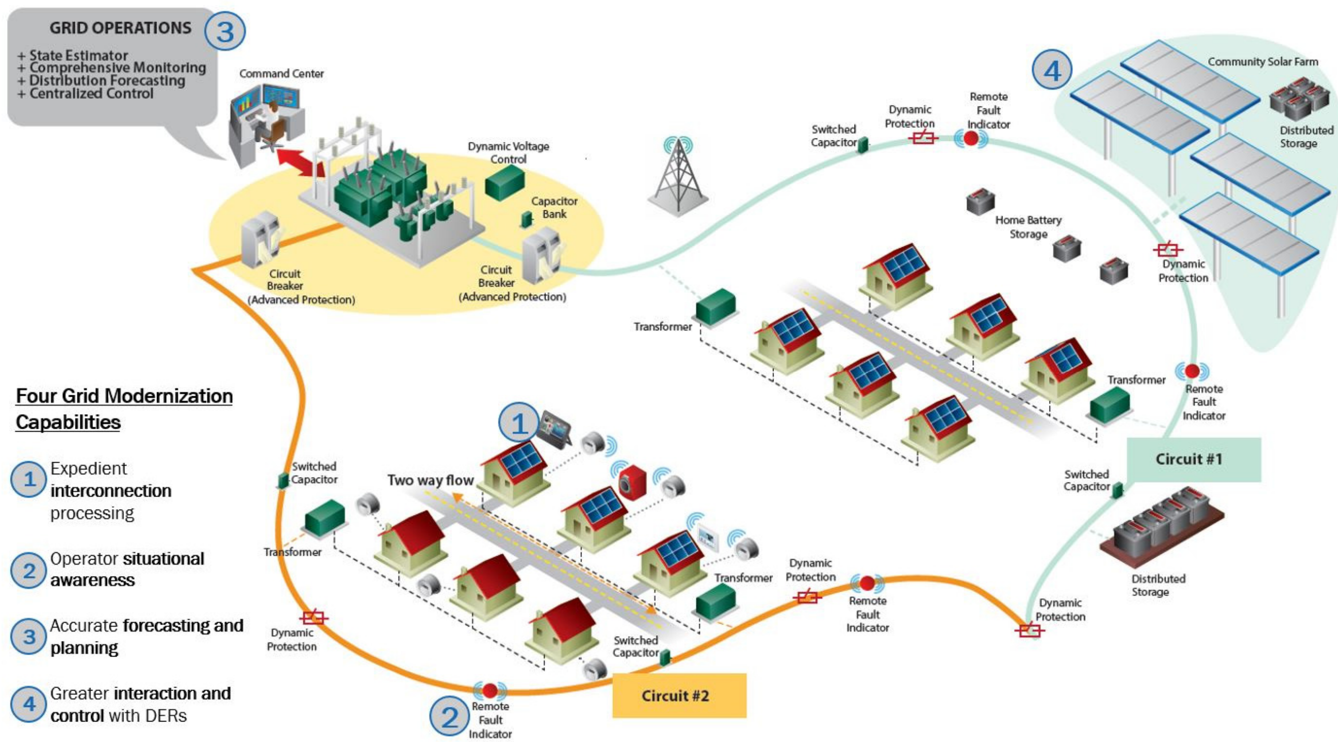
[241] A radial line is a portion of a distribution circuit that is typically composed of smaller conductor that branches off from the mainline circuitry to serve a small number of customers.

energy will vary throughout the day. If not planned for correctly, this variability can lead to equipment overloads or impacts on reliability.

Predicting power production and consumption from DERs is also important in short-term scenarios and for grid operators to meet real-time needs. For example, in areas where there are high levels of solar PV, cloud cover can suddenly decrease solar production and cause power-flow fluctuations. The ability to continuously monitor and control the grid can enable system operators to respond to these changes in real-time to maintain system reliability. SCE also seeks to expand the use of its smart meter data in planning and operations by incorporating the ability to perform new analytics that will help manage the asset use. Effective grid analytics can predict overloads on distribution transformers and circuits, improve response to customers that are experiencing voltage fluctuations, and incorporate predictive algorithms using existing and future load data to assess DER potential.

Finally, greater interaction with DERs will enable grid operators, aggregators, and/or other third-parties to safely and reliably provide grid benefits to customers. Interaction will need to take place through standardized communication signals between dispatchable DERs (either directly or through third party aggregators), the central grid operations center, and any market operators. In addition, for DERs to be relied upon in lieu of traditional investments for reliability purposes, distribution grid operators will need to actively interact with DERs to maximize the value that DERs can provide customers. For example, grid operators may require some functionalities to be provided by smart inverters or energy storage devices during specific system conditions. High DER penetrations will require faster response times and the ability to directly control some DERs remotely will become more necessary to ensure constant reliability and safety. Currently, standardized protocols to facilitate interaction between grid operators and DERs do not exist. As these protocols are developed, technology will be necessary to allow for this interaction.

Figure VII-13
Grid of the Future



Moreover, the distribution system will require additional investment to facilitate Volt/VAR[242] control and power flow optimization to accompany increasing levels of DERs. This will improve voltage control and reduce line losses through the utilization of advanced voltage controls that enable the real-time reduction of voltage within acceptable limits.

In addition to the capabilities that support grid modernization, proactive grid reinforcement measures are necessary to increase grid capacity for DERs. These proactive measures will target circuits with high levels of forecasted DERs to increase integration capacity through conductor upgrades or conversions to higher voltage.

In order to realize the desired electric distribution system capabilities to support the State policy goals discussed above, investments will be required in the following grid modernization categories: distribution automation, substation automation, communications systems, and technology platforms and applications. Table VII-9 identifies investment categories and specific investments in the near term and for the 2018 GRC. These strategic investments will enhance SCE's ability to meet policy goals while increasing the value of DERs to the grid.

[242] Volt/VAR control refers to an optimization algorithm focused on achieving specific voltage and reactive power targets utilizing coordinated control of reactive power devices.

Table VII-9
Grid Modernization Investments and Preliminary Expenditure Estimates

Category	Specific Investments		2015	2016	2017	2018 GRC (2018-2020)
Distribution Automation	#1	Automated Switches w/ Enhanced Telemetry	$500K - $1M	$3 - $5M	$35 - $60M	$185 - $320M
	#2	Remote Fault Indicators				
Substation Automation	#3	Substation Automation	$1.3 - $1.6M	$5 - $10M	$25 - $45M	$185 - $320M
	#4	Modern Protection Relays				
Communication Systems	#5	Field Area Network	$100 - $200K	$2 - $5M	$5 - $10M	$270 - $470M
	#6	Fiber Optic Network				
Technology Platforms and Applications	#7	Grid Analytics Platform	$10 - $13M	$65 - $100M	$55 - $85M	$215 - $375M
	#8	Grid Analytics Applications				
	#9	Long-Term Planning Tool Set				
	#10	Distribution Circuit Modeling Tool				
	#11	Generation Interconnection Application Processing Tool				
	#12	DRP Data Sharing Portal				
	#13	Grid and DER Management System				
	#14	Systems Architecture & Cybersecurity				
	#15	Distribution Volt/VAR Optimization				
Grid Reinforcement	#16	Conductor upgrades to larger size			$140 - $215M	$550 - $1,100M
	#17	Conversion of circuits to higher voltage				

The range in cost estimates reflects both the evolving nature of the underlying technologies, such as intelligent switches, and uncertainties around the timing of development and deployment of the technologies. The range also reflects uncertainty surrounding the pace at which certain grid reinforcement activities, such as reconductoring, can be accomplished. SCE will perform a detailed design of the grid modernization investments outlined above in 2015 and 2016 with deployment of some technologies happening as early as the fourth quarter of 2015 and focusing mostly on circuits located in urban areas. This will include identification of circuits and substations to be automated, a detailed determination of the specific automation to be employed, design of information technology architecture to support necessary technology platforms and applications, and a thorough development of cyber-security measures. Once a more detailed design is completed, future cost estimates can be refined and investments can be deployed.

a) Distribution Automation (#1 – #2) Will Provide Grid Insight, Data for System Planning, and Reconfiguration Opportunities for Grid Operators.

Table VII-10
Summary of Investments in Distribution Automation

<table>
<tr><th colspan="2">Specific Investments</th><th>Description</th><th>Benefits</th><th>Capabilities Enabled</th></tr>
<tr><td>#1</td><td>Automated Switches with Enhanced Telemetry</td><td>Apparatus that captures additional telemetry, including two-way power flows. Devices can operate autonomously or be remotely controlled so that grid operators can quickly isolate outages and monitor/track performance of DERs and the grid.</td><td>Improves reliability, resiliency, and safety for customers. Supports optimization of two-way power flows to maximize grid benefit from DERs.</td><td rowspan="2">Improves operator situational awareness through increased telemetry.

Accurate forecasting and planning is improved through new data and information on DERs effectiveness.</td></tr>
<tr><td>#2</td><td>Remote Fault Indicator</td><td>Apparatus that captures two-way current flows. Helps utilities find equipment failures on the grid so that they can restore power to customers more quickly.</td><td>Improves reliability and safety for customers by decreasing time to respond to abnormal system conditions.</td></tr>
</table>

SCE intends to develop distribution automation to support high DER penetration at forecasted locations by installing telemetry and controls on the distribution system. Investments in distribution automation, such as remote fault indicators, additional remote-controlled switches, and upgrades of existing remote-controlled switches, will provide increased situational awareness as well as the additional data necessary for improved accuracy of short-term forecasting and long-term planning.

Remote fault indicators can provide dual benefits of basic telemetry and immediate indication of system failure locations resulting in decreased time to respond to abnormal conditions. SCE currently has an aging fleet of fault indicators that do not contain this basic telemetry, and SCE envisions this next generation to be a natural replacement. Accelerating the replacement of outdated controls and sensors with newer, more sophisticated versions will increase the situational awareness and remote capabilities for system operators in connection with increased penetration of DERs. These devices are relatively inexpensive and easy to install in a variety of locations, serving as a very versatile solution to improve grid insight.

Likewise, investments in remote-controlled switches with advanced telemetry capabilities can be installed in locations where remote switching can improve reliability. These locations have high exposure to external elements or involve locations where customer impacts can be minimized when performing repair and maintenance activities. In addition to providing system flexibility, remote-controlled switches can give operators real-time situational awareness of DERs and system performance such as voltage, current, and power flow. They also allow grid operators to quickly and remotely reconfigure the system in response to abnormal conditions and emergency situations. Based on a detailed evaluation of required telemetry, system reliability, and cost effectiveness, a combination of remote fault indicators, new switch installations and retrofitting of existing switches will be implemented to achieve the appropriate level of grid insight. As the current fleet of switches becomes obsolete, these new remote-controlled switches will be deployed resulting in additional functionality.

Each distribution circuit will be designed such that the circuit is divided into quarters with the capability to remotely reconfigure each quarter of the circuit so that it is fed from a different circuit when necessary, similar to other self-healing circuit functionality such as Fault Location Isolation and Service Restoration (FLISR). In order to accomplish this, an average of four and a half remote-controlled switches will be installed per distribution circuit. The total number of remote-controlled switches to be installed per distribution circuit includes three remote controlled switches to serve as isolation points and three remote-controlled switches to serve as tie points with other circuits. Counting each "tie" switch as half (because they are shared between two distribution circuits) results in a total of four and a half switches (three "isolation" switches and three "tie" switches). A set of studies has been performed to evaluate the improvements to reliability due to increased distribution automation and are discussed in Appendix H.

With increasing DERs, it is expected that additional distribution automation as described above will provide increased reconfiguration flexibility to grid operators. In addition, an average of ten remote fault indicators per distribution circuit will replace obsolete units to capture telemetry and record fault information on the radials of the distribution circuit. Where possible, existing automated switches will be leveraged and upgraded in place of new remote-controlled switches to provide for similar telemetry and switching capability. This modern distribution circuit design will provide operators with the increased situational awareness and control capability described above.

b) Substation Automation (#3 – #4) Will Support Grid Operations, Enhance Situational Awareness, Improve System Reliability, and Enable Two-Way Flows of Energy and Energy Services

Table VII-11
Summary of Investments in Substation Automation

Specific Investments		Description	Benefits	Capabilities Enabled
#3	Substation Automation	A set of telemetry and control systems within the substation to enable automated processes (e.g., volt/VAR optimization) that are currently done manually.	Reduces the labor required for operating and maintaining the substation. Speeds up the response time within the substation by automating substation processes, thereby enhancing reliability. Enables two-way power flows.	Improves operator situational awareness through increased telemetry. Establishes a gateway for distributed control to allow interaction and control of DERs.
#4	Modern Protection Relays	Advanced substation protection relays that accommodate backflow of power through the substation.	Enables two-way power flows through the system by allowing power to backflow from one part of the distribution grid, through the substation, and into other parts of the grid.	Enables higher penetration of DERs and accommodates two-way power flow on the subtransmission system.

Substation automation includes enhancing telemetry and remote control at substation locations, such as the ability to remotely operate circuit breakers at the substation level. Substations will serve as data and control gateways to distribution circuits that will contain the devices described in Section B.2.a of this Chapter, to support increased interoperability. For example, the operation of a substation circuit breaker can be closely coordinated with the operation of a remote-controlled switch in order to isolate the effect of a system disturbance to a minimal number of customers. Remote-controlled equipment at the substation will also improve response times to abnormal conditions and outages by providing increased data from digital relays that capture and report real-time grid conditions. Grid operators could also interact remotely with substation elements for updates and changes to equipment conditions, which currently can only be accomplished through a manual process.

Substation automation will provide the necessary infrastructure to allow various types of optimization. Traditionally, capacitors operate independently from other grid devices and switch on and off based on local voltage levels. Implementation of a Volt/VAR optimization algorithm provides for centralized control of capacitors and the ability to analyze real-time conditions to determine the optimal state of each capacitor (on/off) connected to a grid location. Substation automation allows for a comprehensive Volt/VAR optimization scheme that includes capacitors located in field locations as well as capacitors located inside the substation. Optimization of DERs for maximum grid benefit will be best accomplished using technology solutions located at each local substation. Automating a substation includes the installation of a gateway device that is a platform on which DERs can be optimized.

At higher penetration levels, energy production from DERs can lead to changes in power flow at the sub-transmission level (*i.e.,* lines typically at voltages of 66 kV and 115 kV). These changes in power flow can cause existing protective relays to operate improperly, leading to impacts to system reliability. Newer, more sophisticated relays can provide additional capabilities such as avoiding load encroachment[243] and directional relaying.[244] Replacing traditional protective relays with modern relays combined with high-speed communications equipment will provide these additional capabilities, which allow for bi-directional power flows (V2G). These types of schemes already need to be deployed on the distribution system in specific areas where there are many DERs. Given the time needed to implement these changes, it is key to begin implementation now.

243 Load encroachment is a protection capability in which the relay can distinguish between normal load current and current that is created due to a fault condition.

244 Directional relaying is a protection capability in which the relay can discern the direction of current before operating.

c) Communications Systems (#5 – #6) Will Allow for Safe and Secure Coverage of Automated Devices Across the Grid.

Table VII-12
Summary of Investments in Communications Networks

Specific Investments		Description	Benefits	Capabilities Enabled
#5	Field Area Network	Field area network is a wireless communications network; the fiber optic networks is a wired connection.	Enables SCE to collect and take in more data securely. Provides for increased control and interoperability with DERs	Supports increased amounts of data which enables increased situational awareness, accurate prediction and planning, and interaction with control of DERs.
#6	Fiber Optic Network			

The expansion of substation and distribution automation will drive the need for advanced communication systems, due to the need for additional bandwidth and wider coverage to support automated devices across the grid. SCE's current field area network uses older technology that functioned well for the demands at the time it was installed, but it is rapidly reaching its capacity limits to integrate new DER-related devices and provide the interoperability needed to enable the use of future DER interfaces through smart inverters and other technologies. Additionally, the network does not have the bandwidth or latency capabilities that will be necessary to support increasing amounts of distribution automation and DER penetration. SCE, and potentially the CAISO or other utilities, will need to process large amounts of real-time information to assess the constantly changing state of an increasingly complex distribution grid.

Necessary communications upgrades include fiber optics and high-speed wireless networks to support the transfer of large amounts of system data (*e.g.*, telemetry from grid devices and DERs, software updates for automation controls, maps and programs for field crews). The fiber-optic network, in combination with local field area networks, provides reliable device communication on the distribution system. This requires SCE to proactively phase in a new field area network consisting of radios, routers, and concentrators that can support increased levels of data and control requirements.

d) Technology Platforms and Applications (#7 – #15) Will Help Speed up Interconnection and Enrollment, Enable Data Sharing and Validation, and Improve Forecasting.

Table VII-13
Summary of Investments in Technology Platforms and Applications

Specific Investments		Description	Benefits	Capabilities Enabled
#7	Grid Analytics Platform	An IT back office software that analyzes, organizes, and manages increased amounts, granularity and frequency of data. An application that allows planners and operators to utilize data that is captured from smart meters, grid devices, and DERs.	Allows operators and planners to leverage large magnitude of data to make effective decisions to improve safety and reliability.	Provides for increased situational awareness and provides additional data that will result in more accurate prediction and planning.
#8	Grid Analytics Applications			
#9	Long-Term Planning Tool Set	Software tool that allows system planners to develop long term forecasts of customer demand as well as DER penetration levels. Allows system planners to model multiple scenarios to determine how DERs impact future needs.	Allows planners to incorporate DERs into long-term planning. Allows for evaluation of DER effectiveness, more sophisticated forecasting, and DERs to be evaluated as alternatives to traditional upgrades.	Provides for more accurate long term planning and incorporation of DERs into system plans.
#10	Distribution Circuit Modeling	Utility tool to model distribution circuits and run various scenarios.	Allows for more sophisticated analysis of distribution circuits (e.g. time-series studies). Facilitates ICA for entire SCE system.	Provides for more accurate planning by allowing planners to expediently model distribution circuits to determine impacts of DERs.
#11	Generation Interconnection Application Tool	Online application tool for customers and third parties to submit interconnection applications	Speeds up interconnection a helps customers and utility engineers save time.	Provides for faster processing of interconnection applications.
#12	DRP Data Sharing Portal	Online map that displays the available capacity to host DERs.	Informs customers and third parties regarding integration capacity.	Supports DER integration through increased data sharing and transparency.

#13	Grid and DER Management	Software upgrades to central grid management systems (e.g. DMS, OMS) to enable real-time grid and DER management. Enables optimization of DERs and grid devices and provides operators with increased levels of information on grid performance.	Creates opportunities for DERs to provide grid benefits; Increases value of the DERs.	Provides for increased situational awareness through access to increased levels of data. Provides for short term predictive capabilities through state estimation. Provides for interaction and control with DERs through advanced control capabilities.
#14	Systems Architecture and Cybersecurity	A set of protocols, system designs, and security programs, which enhance capability by building a stronger systems "backbone" to enable other technology solutions.	Improves cybersecurity to ensure that customer data is safely transmitted.	Provides security and integration of technology platforms and applications to enable faster interconnection processing, increased situational awareness, accurate prediction and planning, and interaction and control with DERs.
#15	Distribution Volt/VAR Optimization	An optimization algorithm that enables more control over the level of power delivered to the end-use consumer.	Potentially lower electric bills; improves reliability.	Provides for interaction and control with grid devices and potentially with DER devices in the future.

SCE has identified the following technology platforms and applications to enhance DER reliability and value to the grid.

(1) Advanced Tools for Long-Term Planning (#7-#9)

Increased DERs will require SCE system planners to expand the data they evaluate for long-term planning. Distribution planners will need to forecast load on distribution circuits and substations to meet forecasted needs. A set of grid analytics applications and long-term planning tools is necessary to evaluate the effects of DER penetration to accurately predict future conditions and plan accordingly.

Investment in a grid analytics platform will increase SCE's ability to leverage smart meter data and grid analytics in support of planning and operations. This functionality will improve the efficiency of grid asset management and operations in all areas of SCE's system and will have the most value where there are high levels of DERs. For example, the ability to forecast distribution transformer overloads and respond to customer voltage complaints is becoming more complex due to increasing levels of DERs. Using smart meter data and grid analytics will improve SCE's ability to proactively manage its assets on a system made more dynamic and complex by increasing DER penetration.

There is a significant opportunity to integrate DR and EE measures into distribution planning and operations. To do this effectively, distribution planners must have sufficient performance information regarding individual and combined DR and EE measures and programs on a locational basis and be able to forecast DR and EE availability to evaluate the potential levels of these resources that can be deployed in a given area. An advanced grid analytics platform will allow for smart meter data to be utilized and analyzed to evaluate the effectiveness of DR and EE to inform short-term operational decisions as well as long-term forecasts and planning to meet customer demand.

In planning a unidirectional grid, SCE used peak load information to plan for sufficient capacity. In the future, SCE anticipates that 8,760-hour profiles (i.e., profiles of demand that encompasses all hours of the year) will be needed to integrate DERs into the planning process effectively. An upgraded, long-term planning tool is needed to support the DRP and the development of a new framework for distribution planning.

In addition, improved analytics can enable the evaluation of various customer types and determine the levels of DR and EE potential. For example, if a particular distribution circuit is forecasted to exceed capacity, distribution planners and customer service specialists could evaluate the potential to reduce demand on the distribution circuit through EE measures. The tool would contain customer data and potential EE measures that could be applied to various customer classes. Through aggregation calculations, the tool would estimate the amount of demand that could be offset on the distribution circuit through EE measures. It would then be possible to evaluate the cost effectiveness of this EE solution compared to a traditional distribution upgrade to determine the best course of action.

(2) Upgrade Distribution Circuit Modeling Software (#10)

The granular nature of the integration capacity analysis as well as the dynamic nature of DERs will require SCE to upgrade distribution circuit modeling software. Currently, SCE utilizes CYME, a power engineering software, to model distribution circuits to perform detailed studies of thermal, voltage, and protection impacts due to generation interconnection. However, the current process for importing circuit data from available resources is largely manual and is limited by CYME's capabilities. As highlighted in Chapter 2, SCE will need to perform an integration capacity analysis on a regular basis to evaluate the capacity for DERs on all of SCE's distribution circuits. In order to perform this analysis, all of the 4,636 circuits will need to be modeled and analyzed using a distribution circuit modeling tool. To effectively evaluate this large number of distribution circuits, portions of the analysis must be automated. This will require upgrades to the current distribution circuit modeling software and the integration points with other SCE system models. Upgrading the software will allow circuit models and data from other resources to be more easily imported into the tool to streamline the analysis.

In addition, upgrades to the software will include dynamic time-series modeling capabilities which are necessary to thoroughly evaluate DERs, such as energy storage and solar PV. Currently, interconnection studies are performed based on a single point in time with limited data from existing resources. This type of analysis represents a worst-case scenario, but does not provide the system planner with a complete picture of the impacts of DERs on the grid. The addition of time-series modeling capability will allow evaluation of DER performance over a period of time providing a more comprehensive analysis of their impacts. SCE has already begun efforts to improve the distribution circuit modeling tool as necessary to meet the DRP requirements and will need to continue these efforts in order to meet future DRP phases.

(3) Automation of Interconnection Application Process (#11)

To accommodate the growing number of DER interconnection requests in an efficient manner, SCE proposes to enhance tools for processing interconnection applications and develop a robust method for capturing data related to interconnection projects. In the past few years, the number of DER interconnection applications has increased dramatically, creating the need to leverage technology to adequately meet customer needs. Customers should have the ability to complete interconnection applications online and utility engineers should be able to process these applications using an automated platform. Ultimately, this automation will reduce the time and cost to accommodate customer interconnection requests.

To achieve this automation, various enhancements are required to allow modeling tools to better integrate with GIS databases and allow distribution planners to easily create and model DER impacts on distribution circuits. A new tool will facilitate timely review of applications and identify problems with applications prior to forwarding them to a planner for final review. This tool will be able to apprise customers of where the application is in the review process and should reduce the interconnection time from submittal of the application to “permission to interconnect.” Besides helping to accelerate the interconnection process, this modern interconnection application tool and associated database will allow SCE to collect DER data from across SCE’s system. This data will allow distribution planners to accurately account for existing DERs and better forecast future penetration levels.

SCE is currently piloting a tool that facilitates NEM application processing using an online application provided by a third party. The purpose of this tool was to respond to both Commission requests to improve the process and to build capabilities to support the rapidly increasing volume of NEM applications. This tool is currently being implemented on a pilot basis, and SCE is currently testing the ability to streamline the review process, manage data, and minimize the amount of SCE resources required to process applications. Once the pilot has concluded, SCE will pursue a long-term solution as described above to select a permanent tool for processing all interconnection applications, including Rule 21 and WDAT projects.

(4) [Development of Portal to Display Results of Integration Capacity Analysis (#12)]

SCE must invest in an external, internet portal to allow customers and third parties to easily access and interpret the results of integration capacity analysis (ICA, is defined in Chapter 2) as well as other shared data. The Distributed Energy Resource Interconnection Map (DERiM) will incorporate the ICA results and include data regarding distribution circuitry information, such as distribution feeder names and topology and circuit-to-substation relationships. This map is intended to serve as a new forum for SCE customers and developers to interact with SCE.

The DERiM incorporates functionality that will allow the user to access the tool from a mobile device, such as an iPad or Android tablet with appropriate internet access. The DERiM also provides filtering functionality, which allows users to filter the data and the distribution circuits displayed on the map by multiple dimensions, such as distribution circuits of a given voltage or distribution circuits with an integration capacity within a user-defined amount. The DERiM allows users to export information from the maps, providing the user access to SCE distribution system information even when offline. The additional data and user-friendly functionality will aid customers and developers in the siting of generation projects.

SCE's DERiM contains distribution circuitry information, such as distribution feeder names and topology, as well as circuit-to-substation relationships. In terms of data types, the DERiM provides three data types listed in the Final Guidance: 1) non-coincident peak load forecast information at the circuit and substation level, 2) capacity at the circuit level, and 3) existing distributed generation population characteristics. In addition to these data types identified in the Final Guidance, the DERiM also provides current penetration levels (*i.e.*, the ratio of generating resources to peak load), projected load, and the results of the

ICA that will be useful for customers and developers to identify locations to interconnect DERs with the least distribution grid impacts and associated interconnection upgrade costs.

(5) Grid Management Tool (#13)

SCE needs a grid management system that can process large amounts of data and present that data to operators in an easily understood fashion to provide increased situational awareness for system operators. In addition, a new grid management system must provide for better interaction with DERs. Increases in DER penetration levels will render the existing grid management systems insufficient to manage the dynamic conditions of the distribution grid. Existing outage management and distribution management systems provide operators with limited visibility to system conditions. For example, the power flow on a distribution circuit is typically recorded at the substation. This means that operators do not have visibility to the production and consumption of electricity along the distribution circuit and are unable to monitor power flows at switches or transformers beyond the substation fence. This data is already needed to support reliable operations in some locations in SCE's service territory.

Increased levels of distribution automation will provide voltage and current data along the distribution circuit and will serve as inputs into a centralized grid management system that includes system state estimation algorithms.[245] This functionality can process the voltage and current data that is collected from remote-controlled switches, remote fault indicators and capacitors, and use advanced algorithms to estimate the load flow at any point along the distribution circuit. As levels of DERs increase, it will be increasingly necessary to estimate and monitor load flows to fully understand the circuit reconfigurations needed to isolate system issues, balance system load, or facilitate maintenance and

[245] A state estimation algorithm can estimate values of parameters on the distribution system based on measured data at various locations throughout the system. The estimator attempts to approximate unknown values based on the measured values.

construction activity. A new grid management tool will incorporate system state estimation and thereby provide operators with the necessary information for making operational decisions during normal and abnormal system conditions.

In addition, the new grid management tool must be able to interact with and control DERs to meet local needs and must provide operators with information necessary to make correct decisions. High penetration of DERs, such as solar PV, energy storage, and electric vehicles, will cause increased fluctuations in distribution system characteristics, such as voltage and current. The dynamic nature of distribution circuits will require operators to manage DERs in response to these shifting conditions. Without the ability to interact with and control DERs, the ability for DERs to serve as alternatives to capital projects will be limited. For example, an operator may call upon a number of solar PV inverters to change the power factor at the point of delivery to mitigate a voltage concern or an operator may require an energy storage device to charge and discharge at specific points in the day in order to limit thermal overload conditions. A new grid management system will be necessary to provide operators with information on DER performance that are connected to the grid and an understanding of the capabilities that the DERs have to mitigate system issues and the individual or combined level of operating impact on a circuit segment.

(6) System Architecture and Cybersecurity (#14)

All of the above mentioned technology platforms and applications must be strategically integrated into SCE's systems in an efficient manner. This will require advanced system architecture measures to ensure data integrity, system integration, robust contingency response, and cybersecurity protections. An effective system architecture design will outline specific sets of data that will serve multiple software systems and ensure that these data sets maintain integrity, remain consistent with similar datasets, and have contingency schemes in place so that the data does not become compromised or corrupt. In addition, the system architecture design will specify how these data sets are used across systems so that all available data can be used to provide the most accurate results.

A more modern grid will result in increased amounts of information, data and control points and interfaces. If not planned for correctly, this new type of infrastructure could create increased vulnerability to cyberattack. It is imperative that grid modernization technologies include robust cybersecurity measures to provide for a secure and redundant network that can maintain customer safety and reliability.

(7) Volt/VAR Control (#15)

Deployment of distribution Volt/VAR control schemes will allow SCE to reduce energy consumption and provide for a centralized scheme to manage voltage and power factor across distribution circuits. Traditionally, capacitors operate independently from other grid devices and switch on and off based on local voltage levels. Implementation of a Volt/VAR optimization algorithm provides for centralized control of capacitors and the ability to analyze current conditions to determine the optimal state of each capacitor (that is, on or off) connected to a grid location. Implementing the algorithm consists of software programming into a substation control system.

3. Grid Reinforcement Investment Plan: The Need to Increase Distribution Grid Capacity to Accommodate Higher DER Penetration

Grid reinforcement investments will increase the capacity of the grid for DERs and advance a "plug-and-play" grid. Building a "plug-and-play" electric distribution system for broad access to customer-side DERs requires a rapid evolution in planning, design, and technology integration. As such, beginning in 2015 and over the course of the proposed grid investment program, SCE proposes to make grid upgrades in areas where high numbers of DERs are anticipated to provide system benefits and may serve as alternatives to traditional capital upgrades.

Grid reinforcement is also intended to proactively address the susceptibility of the power system to "choke points" and congestion as DER penetration levels rise. Safety, reliability, and resiliency require continued focus on the physical utility infrastructure in addition to the adoption of the next generation of automation technologies. As SCE continues to replace its aging infrastructure to support safety, reliability, and resiliency, SCE believes these activities need to be integrated with new infrastructure deployment to best manage costs in a "dig once"[246] approach. This approach is consistent with SCE's goal to reduce costs and increase efficiency of upgrading and adding new infrastructure.

Determining how to best address the design of the future distribution system requires a closer review of how DER integration is limited by the current design of the one-way grid. For example, within SCE's service territory, there are a significant number of residential neighborhoods that are served by a 4kV distribution system. These systems were installed decades ago and have been steadily converted to a higher voltage to support the ability for customers to add load and maintain voltage. Accelerating the conversion to a higher voltage system will enable increased penetration and usage of residential solar PV and other DER technologies. Another example includes the number of small conductors within the utility distribution system to support one-way power flows from the substation to the customer. These designs often support the use of larger conductors at the substation and smaller conductors at the ends of circuits. Upgrading the small conductor that is located near the end of distribution circuits can increase the capacity for DERs and, as an increasing number of generation sources are added to the grid, larger conductors should, in any event, replace smaller conductors in order to minimize the occurrence of downed power lines.

While these types of investments are part of the current General Rate Case, the current review of ICA suggests that conversion of 4kV systems to higher voltage and increasing conductor size at the end of distribution circuits are specific measures that can be taken to accommodate higher levels of DERs. As such, work on the 4kV systems and upgrading conductor, as outline above, needs to be accelerated. Performing accelerated

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[246] Policy Brief on Dig Once, US Department of Transportation, June 2012. *See* http://www.fhwa.dot.gov/policy/otps/policy_brief_dig_once.pdf.

grid reinforcement with respect to areas where DER penetration is increasing and where the existing facilities are limited by integration capacity is consistent with the "dig once" approach, while supporting the goal to seamlessly integrate DERs.[247]

Table VII-14
Summary of Investments in Grid Reinforcement

Specific Investments		Description	Benefits
#16	Conductor upgrades to larger size	Increasing conductor in strategic areas to increase the capacity for DERs.	Allows for increased levels of DERs which can increase the total value that DERs can add to the grid
#17	Conversion of circuits to higher voltage	Converting circuits and substations from 4kV to a higher voltage such as 12kV or 16kV.	

C. SCE Is Requesting a Memorandum Account to Capture the Costs of Incremental Investments Prior to the Next GRC

SCE strongly believes that enabling DER growth, while supporting system safety, resiliency, and reliability, is the role of a 21st century electricity system. To support the Commission's DRP goals and given the lead times involved with acquiring and developing technology and performing grid work, SCE will begin, under the grid modernization and grid reinforcement investments plans outlined above, to install the tools and acquire the data to support the integration of DERs into system planning and operations and animate the additional DER market opportunities envisioned by the Commission. Some of this work has already begun, in order to meet the requirements specified in the Final Guidance (*e.g.,* Integration Capacity Analysis). Other work will continue, and will be shaped and guided by the results of DRP demonstrations projects, and Commission's orders.

247 In addition to the grid reinforcement investment categories identified in this section and in Table VII-9, SCE also believes circuit breaker replacements would support grid reinforcement. While not part of SCE's initial estimate, SCE anticipates that circuit breaker replacements could be needed in future GRC cycles to support a more robust grid and enable DER penetration.

Given the size of SCE's system, it will take many years to complete modernization and reinforcement efforts and to fully integrate a new set of tools, technology, and processes. It will also take time to develop, test, and deploy the various technologies needed to enable interaction of the grid and customers with large numbers of DERs. As discussed above, SCE has identified a set of projects that are foundational in nature -- they are needed under any scenario that envisions future DER growth because they maintain grid resiliency, improve interconnection processes, provide for increased DER service opportunities and serve grid reliability.

Because SCE's 2015 GRC was filed in 2013 and predates the DRP, the 2015 GRC did not include the grid modernization expenditures. The Commission has also not yet issued a decision in the 2015 GRC, so there is uncertainty as to how much funding SCE will have available. Consequently, SCE proposes that the Commission permit SCE to file a Tier 1 Advice Letter that would establish the Distributed Energy Resources Memorandum Account (DERMA). SCE requests to establish the DERMA to record the capital revenue requirement (*i.e.,* depreciation, return on rate base, property taxes, and income taxes) associated with grid investments set forth in this chapter and in connection with the system upgrades, if and as they may be needed, for Demonstration Projects C, D and E as described in Chapter 2, and any applicable O&M expenses incurred during the years 2015-2017 that are incremental to amounts authorized in the forthcoming 2015 GRC decision. Establishing the DERMA will allow SCE the opportunity to recover the incremental revenue requirement associated with these new and unanticipated capital expenditures and O&M expenses if they exceed levels authorized in SCE's test year 2015 GRC. This review would take place in SCE's test year 2018 GRC. SCE believes this proposal is consistent with PUC Section 769(d), which states that "[a]ny electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation."

Two of the demonstration projects for which SCE will seek to record costs in the DERMA are located in a geographical area that SCE is currently utilizing for its Preferred Resources Pilot (PRP) and Integrated Grid Project (IGP). This area is receiving some funding through the Commission's EPIC program. SCE has accounting mechanisms in place to separate costs among the various funding mechanisms, so there is no risk of double recovery.

In September 2016, SCE expects to file its 2018 GRC application. As in any GRC, SCE will describe the programs and costs needed to maintain distribution system reliability. SCE will include programs and cost related to continued investments needed to support DERs. SCE will base its GRC request on a forecast of distribution loads for circuits and substations, which is based on the methodology established in the DRP, to identify additional locations where infrastructure investments may be deferred or avoided by DERs deployment. SCE's forecast will reflect assumptions based on its experience with demonstration projects and insight from other previous DER deployment. SCE proposes to review the incremental revenue requirement, and underlying capital expenditures, and O&M expenses recorded in the DERMA in its 2018 GRC application, and will include the balance recorded in the DERMA in SCE's 2018 GRC test year revenue requirement.

Chapter 8:
Coordination and Phasing

VIII.

CHAPTER 8: COORDINATION AND PHASING

A. Introduction and Executive Summary

SCE's DRP is intended to further California's GHG reduction objectives and increase customer choice and engagement, by providing a foundation for substantially increasing integration of DERs into SCE's distribution system planning, operations, and investments. To implement SCE's DRP and accomplish these fundamental goals, it is important to understand the impact of DER penetration on SCE's system, including the load and energy forecasts, power generation, and infrastructure development. As such, the various proceedings and processes in which these issues are addressed – the GRC, LTPP, TPP, and IEPR – must be synchronized with the DRP to provide consistent information about DERs. For example, load forecasts influence grid improvements that need to be made to ensure system reliability. Additionally, load forecasts – coupled with forecasts of energy and capacity positions – drive future procurement decisions. As greater penetration of DERs influence both load forecasts and procurement needs, it is important to assure that there is coordination among various proceedings that touch on these issues.

The Final Guidance directs utilities to: (1) "describe how the results of the DRP will influence their own internal load forecasting, the CEC's IEPR load forecast and by extension the Commission's LTPP and the CAISO's TPP;"[248] (2) explain how the subsequent DRP phases will interact with their respective GRCs and other funding authorizations and include "a plan for how their DRPs can be updated on a biennial filing cycle;"[249] and (3) provide a proposal that either "adopts, or adopts with amendments" the Commission Staff's

[248] Final Guidance, p. 11.

[249] *Id.*

recommendations "for a phased approach to the DRP process over a 10-year time horizon."[250]

In following the Final Guidance, Section B of this chapter describes improvements that can be made in utility forecasting and other recommendations that can support long-term forecasting capabilities. Section C provides a recommendation for coordination between the DRP and the GRC — including a recommendation for updating the DRP — and a recommendation for coordination between the DRP and other funding authorizations. Section D discusses SCE's proposal to adopt, with some additional recommendations, the Commission's proposed phasing approach to future DRPs.

B. Coordination with Utility and CEC Load Forecasting

The Final Guidance directs utilities to comment on how DER forecasts within the DRP process will influence load forecasting, and by extension, the CPUC's LTPP and the CAISO's TPP. Although the DRP is primarily focused on the implications of substantially increased penetration of DERs in local areas, it is important to also understand the implications that DERs have, in aggregate, on the transmission system. Historically, the distribution level and system level forecasts have not been well reconciled because each served separate planning purposes that were not well integrated. With increasing DER penetration, the need to integrate these processes will be more important due to the influence that distributed resources will have on the bulk electric system. Forecasting of DER deployment at a local level must be considered when producing SCE's system-wide load forecast. The increased granularity of the information on customer demand and resource performance is necessary to plan and reliably serve load during all conditions. SCE's internal load forecasting processes will require new tools and processes to implement these changes.

[250] *Id.*

1. The CEC's and SCE's Current Load Forecasting Processes

The CEC's IEPR demand forecast is a biennial process with an interim-year update currently applied at SCE's system level for the entire region. The main focus has been to support system level planning activities associated with CPUC's LTPP and the CAISO's TPP. The process starts with collecting each utility's latest forecasts and historical data, as well as establishing other inputs (such as economic vendor forecasts). SCE's system-level forecast uses a top-down approach,[251] forecasting coincident SCE system peak based on an econometric analysis of economic and demographic indicators. This forecast is done at the bulk power (AA Bank substation) level.

In addition, SCE develops a separate distribution-level load forecast through a bottom-up approach[252] that forecasts the non-coincident circuit and substation peaks, considering local historical load growth trends, the impact of weather, economic and demographic data, and specific developer plans.[253] This forecast is aggregated to B-bank and then to A-bank substation levels.

SCE then uses the system-level forecast results, combined with the forecast developed at the distribution level, to produce its Annual Transmission Reliability Assessment (ATRA), which integrates with the CAISO's TPP. Since these two forecasts were created for different purposes and not fully integrated, the DRP represents an opportunity to begin aligning and integrating efforts across the various planning agencies. Working

251 SCE's system level forecast mainly focuses on aggregated energy and peak demand forecast over SCE's entire service territory. The input information is primarily economic and demographic indicators by geographic areas, typically by county. SCE's system level forecast is expanded to an 8760 hourly load forecast. The forecast is also broken down by customer revenue classes (*e.g.,* residential, commercial, and industrial, etc.).

252 SCE's distribution level forecast is aggregated up based on the grid hierarchy. It produces a 10-year non-coincident annual peak demand forecast for individual circuits that is aggregated to B-bank (66 kV, 115 kV) and then to A-bank (220 kV) substations. It does not produce a corresponding hourly forecast.

253 A.13-11-003, 2015 SCE GRC, Exhibit SCE-03, Vol. 3, pp. 8-13.

towards this integration will require the use of more granular data, new reconciliation processes, and new tools.

The table below describes system classifications and typical transformation voltages within each system.

Table VIII-15
SCE System Classifications and Transformation Voltages

Classification	Substation	Transformation Voltages
Bulk Power	AA Bank	500 kV – 220 kV
Subtransmission	A Bank	220 kV –115 kV, 220 kV-66 kV
Distribution	B Bank	66 kV – 16 kV; 66 kV – 12 kV; 66 kV – 4 kV

2. Transformation of the Future Load Forecast Processes

To enhance its DRP and support future DRP analyses, SCE will need to modify its future IEPR system load forecast by starting at the A-bank (220 kV) substation level. This level is one step further down from the CEC's current AA Bank level. This change will require SCE to reconcile its bottom-up distribution level forecast from the circuit level to this A-bank level forecast. If the CEC's IEPR forecast can be lowered to the A-bank level, then SCE can refine its processes to reconcile/align the two forecasts and enable new assumptions about load and DER growth to influence the forecast at the system level. That alignment will allow utilities to continue providing required inputs to the CEC's forecasting process consistent with the CEC's future requirements, and permit a more granular forecast.[254]

[254] SCE understands that there are potentially significant challenges with transforming its internal load forecast, particularly due to the time and resources that will be required to achieve this transformation. At the same time, SCE recognizes the strong benefits of adapting its internal forecast to meet the future more localized planning efforts and providing more valuable insight for both the utility's and state's forecast and planning activities including CEC's IEPR, CPUC's LTPP, and CAISO's TPP.

Improvements to SCE's internal load forecast process and the CEC's IEPR load forecast process will also influence the CPUC's LTPP and the CAISO's TPP by providing more granular inputs that better integrate with distribution forecasts. Through adoption of the A-Bank level as the common standard, all resource estimates would be developed around the same geographic areas, and issues of reconciling data for each of these processes would be eliminated.

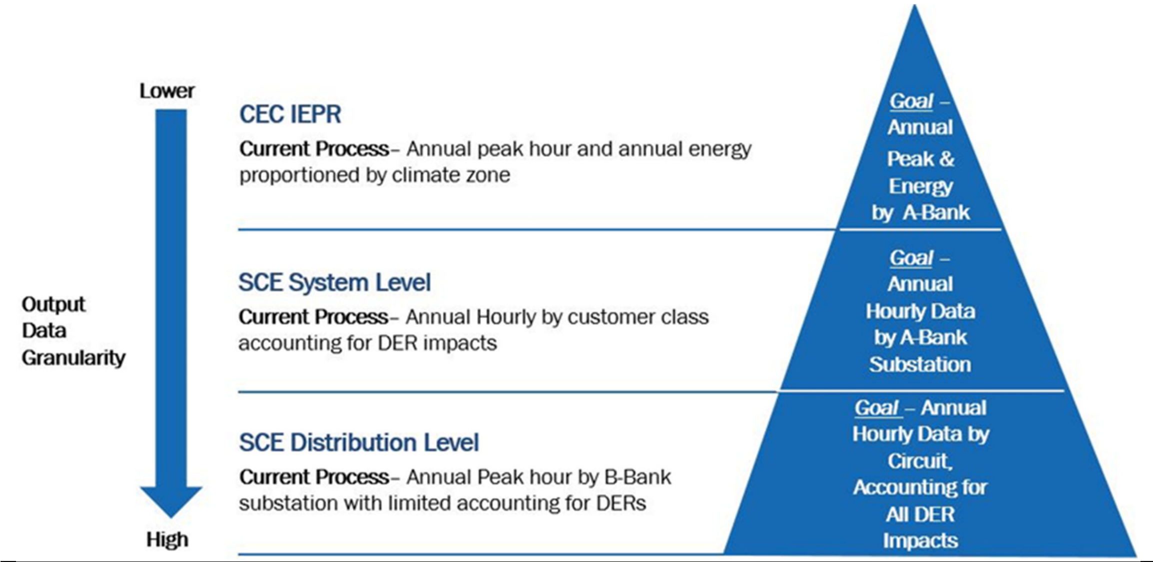
Further, as part of the transformation of the future load forecast processes, SCE believes a higher level of coordination among state agencies (*e.g.,* CEC, CAISO, and CPUC) will become more critical in future planning efforts to integrate both the use of the data, and to better align the timing of these various processes. A higher level of communication and coordination between CAISO's TPP, CEC's IEPR, and CPUC's LTPP and DRP is also necessary to build more consistency across the different planning efforts.

In addition to the increasing level of coordination, stakeholder groups must be expanded to include more parties from distribution planning areas, third-party DER developers, local governmental agencies, etc. The CEC's current Demand Analysis Working Group (DAWG) was developed to provide a venue for stakeholders to work together to resolve detailed issues related to the state's demand forecast. It includes representatives from the state agencies and the utilities. This working group could serve as a model for a new expanded stakeholder group for distribution planning. Stakeholders will work together to keep exploring industry best practices in various forecasting efforts such as best models for forecasting customer adoption in DER potential studies.

3. Recommended Action to Support Recommended Changes to Forecast Processes

Going forward, SCE proposes a long-term plan (3-5 years) to revise the forecasting process. Figure VIII-14 shows the 2020 end state vision, which aligns the CEC IEPR, SCE system-level, and SCE distribution-level forecasts.

Figure VIII-14
Load Forecasting "2020 End State Vision"



The results of the updated distribution level forecast process will produce hourly output for each circuit that incorporates all DERs. The circuit information can then be aggregated to the B-Bank and then the A-Bank substation level. The updated system level forecast will still provide the annual coincident and non-coincident peak demand and annual energy but will be aligned with the distribution level forecast at the A-Bank substation level. The consistency created by the alignment at the A-Bank substation level developed through the updated integrated process will set a sound foundation to support both internal and external decision making, including investment, procurement, and regulatory decisions.

SCE will need to reexamine and define new requirements for each step of the load forecast process. The cornerstone of integrating the forecast is development of a common database containing the fundamental input data. Using a common database promotes consistent use of input data, assumptions, and methodologies. SCE will evaluate different tools for forecasting and allocating potential DER impacts to load to select the most appropriate tool. The process must also take into account the incremental DER development at specific locations, as identified in the most recent DRP. SCE will need to develop internal capabilities to estimate the technical and economic potential of DERs at the various levels of granularity.

Investments in new forecasting tools to manage the increased volume of data will be necessary as capabilities are expanded. For example, in the DRP, as part of its proposed grid modernization investments, SCE proposing to develop new software tools to do geospatial forecasting (the use of mapping tools and techniques such as satellite imagery to inform forecasting assumptions) and further integrate DERs into forecasts and long term plans (*i.e.,* Long Term Planning Tool Set).[255] SCE must develop new tools and methods to allow the new aligned forecast to meet the objectives of both existing forecasts along with new geospatial forecasts of DERs.

SCE will need to perform more scenario planning analyses based on estimates of integrated DER impacts at a granular level. However, as data granularity increases, there is a risk that forecast inaccuracy or uncertainty may increase. The best way to compensate for this increased degree of forecast error due to increased granularity is to place more focus on scenario assessments. Scenario forecasting should be the foundation for decisions ranging from resource procurement to grid improvements.

C. Coordination with General Rate Case and Other Funding Authorizations

1. DRP Coordination with the GRC

The Commission correctly observed in its Final Guidance that one of the most critical components of the DRP process will be its interface with the utilities' General Rate Cases (GRC).[256] The DRP process will influence SCE's investments in distribution infrastructure that it identifies in its GRC. As described below, SCE's annual distribution planning process will evolve to account for the value of DERs to the grid. As this happens, SCE will use this process to identify investments that can or cannot be deferred by DER deployment as well

[255] More information on the proposed tools is included in DRP Chapter 7, Section B.2.d.

[256] Final Guidance, p. 11.

as investments that are necessary to facilitate and integrate DERs in distribution operations. This interface will become increasingly clear as the DRP matures and its tools, methodologies, and demonstration projects are developed and put into effect. SCE envisions the following interface between the DRP and the GRC:

a) The DRP Will Develop a Distribution Deferral Framework

SCE recommends that a distribution investment deferral framework should be developed in the DRP proceeding. The Commission should invite stakeholder comments regarding the principles and guidelines for such a framework. Once such principles and guidelines are adopted by the Commission, SCE and other utilities can develop upfront standards and criteria which can be used to determine which traditional grid investments would be considered for potential deferral by DERs. The DPRG process would review how this framework was applied in identifying deferral opportunities.[257]

b) The DRP Will Develop DER Policies, Tools, and Methodologies

The DRP should also establish DER policies, tools, and methodologies. These tools and methodologies will be incorporated into the annual distribution planning process to identify optimal locations for DERs and capital investments that support DERs. Such tools and methodologies would include the Integration Capacity Analysis, new forecasting approaches, and LNBM, among others.

c) SCE Will Utilize the New Tools and Methodologies to Develop a Distribution Substation Plan (DSP), in Compliance with the Deferral Framework

SCE plans to modify its annual internal distribution planning process to incorporate new tools and methodologies developed in the DRP. For example, SCE's planning process will take into account the DER hosting capacity via the Integration Capacity Analysis.

[257] The DPRG is described in Chapter 2, Section C, Subsection C.

Likewise, SCE will rely on the forecasting tool proposed in Chapter 7, which will allow SCE to better integrate and plan for DERs throughout its distribution system. One objective of SCE's modified planning process would be to identify optimal locations where DERs could potentially provide reliability services.

The output of this internal planning process will continue to be SCE's annual Distribution Substation Plan (DSP), which currently feeds into the GRC forecast. Going forward, SCE's DSP will include a description of how SCE complied with the deferral framework, using the various tools and methodologies, in addition to listing utility investments to be included in SCE's next GRC.

d) SCE's DSP Will Guide Actions or Investments Included in Future GRCs

The results of the DSP will determine what actions or investments SCE pursues in the following GRC Application. Information in the DSP will drive changes in the distribution forecast (or local forecast) and impact the level of traditional grid investment needed to support load growth. The DSP, which has a longer time horizon than the GRC, will provide the basis for the type of investments that are requested as part of the upcoming GRC.

SCE's next GRC will forecast a revenue requirement for 2018 through 2020, and will also include a forecast of capital expenditures for the period 2016 - 2020. SCE will submit its application for that cycle on September 1, 2016. SCE's 2018 GRC will reflect changes to SCE's current planning process to incorporate new DRP tools and methodologies. For example, SCE plans to change its load growth forecasting process by more thoroughly reviewing the potential impact that DERs might have in reducing load and in increasing local capacity. In addition, SCE will also carefully review utility projects, especially those identified in the later years of the GRC, for possible deferral by DERs deployed in selected areas. This analysis could include a review of which projects SCE may be able to defer based upon when the project is needed, as well as the time required to solicit, procure, and implement possible DER solutions.

Consistent with the underlying statute, cost recovery for much of the grid investments needed to achieve the Commission's objectives in the DRP will be requested, reviewed, and authorized in the GRC.

e) Future DRP Proceedings Should Continue to Address Policy Issues and Changes to Tools and Methodologies and Should Ultimately Align With Each Utility's GRC

As part of the Final Guidance, the Commission has identified many policy questions that will need to be considered. The DRP process can be used to address these policy issues and evaluate additional tools or changes to tools and methodologies. It is appropriate to have the DRP take place on a biennial basis as guidelines, policies, and methodologies are developed. However, in the long run, SCE anticipates that the DRPs will no longer need to be biennial (and common across utilities); the DRP can feed into and inform each utility's future GRCs.

2. Coordination of DRP with Other Funding Authorizations.

The DRP Ruling identifies several "Related Proceedings and Processes that Overlap R.14-08-013."[258] The DRP Ruling also notes that "it is essential that Commission Staff and the Utilities make every effort to maintain close coordination among all of these proceedings in order to prevent duplication of effort, conflicting priorities and wasted economic investments."[259]

Outside of the GRC, there are several proceedings that will require close coordination to achieve the long-term objectives established in the DRP proceeding. These include, but are not limited to, Energy Efficiency (R.13-11-005), Demand Response (R.13-09-011), Integrated Demand-Side Management (IDSM) (R.14-10-003); and the Energy Savings Assistance (ESA) program. These proceedings have established goals, objectives, and

258 Final Guidance, p. 10.

259 *Id.*, p. 11.

policies tied to the deployment of DERs that will need to be coordinated to support the DRP, as the Commission envisions. To this end, the Commission has taken a great first step to identify coordination and alignment opportunities across various DSM-related proceedings through the IDSM rulemaking. Within the IDSM rulemaking, the Commission acknowledged the need for coordination in the planning, procurement, administration, and measurement of DERs across the various proceedings.

SCE believes that demand-side management portfolios could support the objectives of the DRP with further coordination and alignment of policy objectives and guidance for each portfolio. For example, existing energy efficiency portfolios are designed to achieve all cost-effective[260] energy efficiency while complying with all Commission policy guidance and directives for these portfolios. Currently SCE's energy efficiency programs are designed and approved to achieve aggregate system-level kWh and kW savings goals. These programs are significant drivers of the State's achievement of its GHG targets.[261] However, if the Commission seeks to utilize these energy efficiency programs to additionally serve local grid reliability purposes in the future, requisite policy objectives and guidance should be developed to allow for alignment of goals and funding for future energy efficiency efforts.

As summarized below, the Commission has adopted several funding cycle structures for various customer-side DER portfolios. Therefore, the Commission and IOUs will need to maintain close coordination to the extent that future DRP updates suggest additional DER policy or deployment modifications that need to be undertaken in their respective proceedings.

[260] Pursuant to the California Standard Practice Manual, IOU energy efficiency portfolios are measured under a two pronged test that includes the Total Resource Cost (TRC) and Program Administrator Cost (PAC) tests.

[261] The California Air Resources Board's Scoping Plan to implement AB 32, the Global Warming Solutions Act of 2006, identifies energy efficiency as a key GHG reduction strategy.

- Energy Efficiency: Through R.13-11-005, the Commission is developing the framework and guidelines for a “rolling portfolio” structure that would develop EE portfolios with Commission-approved long-term funding (*e.g.,* 10 years) and require program administrators to periodically adjust portfolios as circumstances warrant, rather than filing entire portfolios for Commission review on a fixed schedule.
- Demand Response: Through R.13-09-011, the Commission has approved two years of bridge funding for the current DR portfolios, from 2015-2016.
- Energy Savings Assistance: The ESA program is currently funded in three-year program cycles. The current program runs from 2015 – 2017.
- Energy Storage: Through D.14-12-033, the Commission provided funding for the Self-Generation Incentive Program (SGIP), which provides incentives for customers to install self-generation and energy storage equipment, on an annualized basis through 2019.
- Customer Solar: Funding for SCE’s portion of the mass-market California Solar Initiative program has been fully committed.

As the Commission, the IOUs, and stakeholders develop the methodologies and systems to be used in the DRP, they should collectively evaluate how various DSM portfolios can or should be modified to support DRP efforts through each applicable proceeding. Depending on the nature of the modifications, these changes might be made through existing fund-shifting authorizations, Advice Letters, or through future portfolio funding Applications. Throughout, SCE expects that a highly coordinated effort between the IOUs, the Commission, and stakeholders will be necessary to ensure that the individual objectives of the DRP and DSM proceedings are satisfied, while also meeting shared objectives of the utilities, CPUC, CEC, CAISO and other stakeholders.

D. SCE Supports the Commission's Proposed Scope of Future DRP Phases

The Commission proposes a two-phased approach for future DRPs. SCE supports the Commission's proposed phases. SCE commends the Commission's ambitious, forward-looking recommendations. SCE proposes to adopt the Commission's phased approach to DRP filings, and offers the following recommendations.

1. SCE Recommends That the Commission Consider Results of the Demonstration Projects in Future Phases of the DRP

SCE recommends that Phase 2a and 2b of the DRP explicitly incorporate results and data obtained from the DRP demonstration and deployment projects to assist with each phase's larger goals. As required by the Final Guidance, SCE has proposed five demonstration projects to demonstrate the capabilities of DERs to meet grid planning and operational objectives, and each is scoped to commence either no later than six months or no later than one year after Commission approval of the DRP. Since these projects are anticipated to commence in either September 2016 or March 2017,[262] meaningful results from these demonstration projects may not be available by the start of Phase 2 in 2018. SCE recommends that the Commission incorporate lessons learned from these ongoing demonstration projects as results are obtained. For example, the Final Guidance requires utilities to demonstrate, as part of a microgrid, DER dispatch to serve a significant portion of customer load and reliability. Lessons learned from this demonstration project can help inform Phase 2a, where utilities "specify tools and processes to compare DERs as alternative providers of distribution reliability functions."[263]

To facilitate the process of information sharing and incorporating lessons learned into future DRP cycles, SCE plans to provide a final report on all completed demonstration

262 SCE estimates that the Commission decision approving SCE's DRP will be provided on March 2016; 6 months from March 2016 is September 2016 and 1 year from the Commission's decision is March 2017.

263 Final Guidance, p. 12.

projects. For projects not yet completed by the end of the Phases set forth by the CPUC, SCE will report on the status of the demonstration projects with SCE's future DRP policy filings. These reports will be publically shared, and include updates about the progress, achievements, and lessons learned in executing these demonstration projects. These reports may also include recommendations to future phases of the DRP proceeding.

2. In Phases 1 and 2a, Data Sharing Issues Should Be Explored via SCE's Proposed Workshops

The Commission's proposed phases contemplate the need to provide additional data – for example, Phase 1 states that deliverables include "GIS maps and power flow models of the entire distribution system" and Phase 2a requires an output of "Distributed Energy Resource Develop Zones."[264] In Chapter 3,[265] SCE recommended an open stakeholder process to address sharing of data types identified in the Final Guidance. These workshops would be modeled after Phase III of the Smart Grid proceeding. In these workshops, stakeholders would discuss different data uses, the frequency and granularity of the data needed, and applicable data privacy laws and rules. The workshops would lead to a joint proposal that would be submitted to the Commission for approval. SCE recommends that stakeholders continue to utilize this process in the future to discuss data needs as such needs evolve.

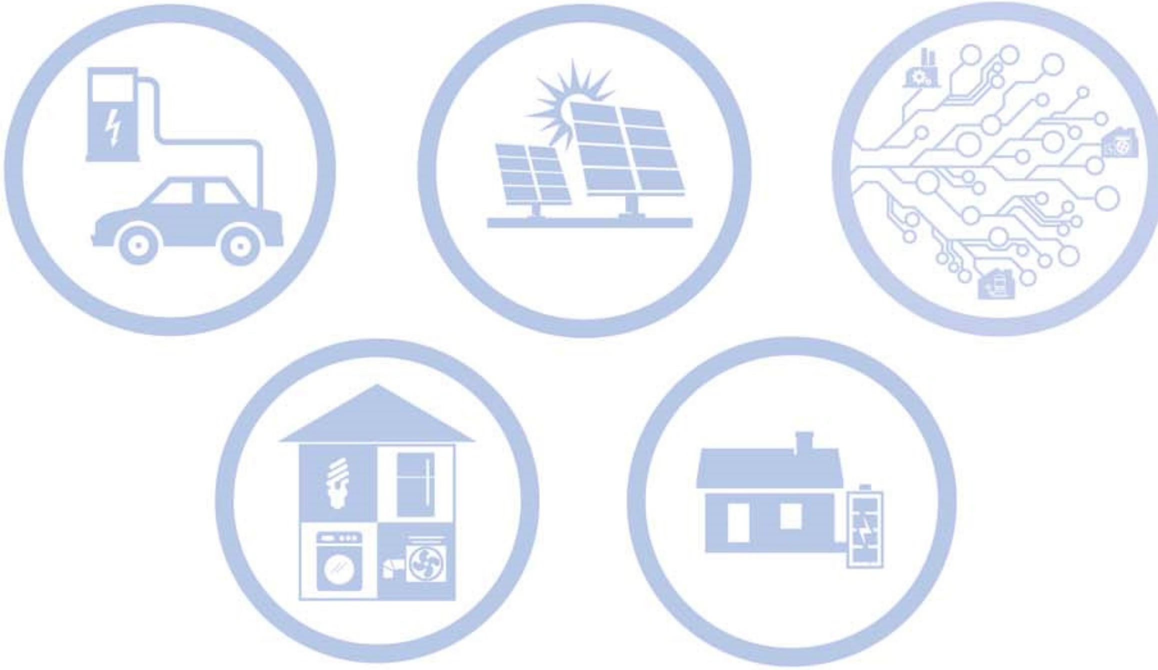
3. SCE Recommends Creating a Distribution Planning Review Group

As discussed in Chapter 2, SCE recommends that the Commission consider adopting a Distribution Planning Review Group (DPRG) process to review each utility's application of the deferral framework described in Chapter 8, Section (C)(1), above. This DPRG process would be similar to the Procurement Review Group (PRG) process the Commission has adopted for the review of the utilities' procurement activities in the wholesale energy and

264 *Id*.

265 Ch. 3, Section D.

emissions markets. This process would enable the Commission and the utilities to strike a balance between transparency and contemporaneous discovery, on the one hand, and protection of confidential information, on the other.



SOUTHERN CALIFORNIA
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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of Its Distribution Resources Plan	))))	Application No. 15-07-_____ (Filed July 1, 2015)

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of **APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) FOR APPROVAL OF ITS DISTRIBUTION RESOURCES PLAN** on all parties identified on the attached service list(s) **R.14-08-013.** Service was effected by one or more means indicated below:

☒ Transmitting the copies via e-mail to all parties who have provided an e-mail address.

☒ Placing the copies in sealed envelopes and causing such envelopes to be delivered by hand or by overnight courier to the offices of the Commissioner(s) or other addressee(s).

CALJ Karen Clopton
ALJ David M. Gamson
CPUC - DIV of ALJ's
505 Van Ness Ave, Room 5115
San Francisco, CA 94102

Executed this July 1, 2015 at Rosemead, California.

/s/ ***David Balandran***
David Balandran

Project Analyst
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Appendices

Appendix A: Acronyms

AAEE	Additional Achievable Energy Efficiency
AB 327	California Assembly Bill 327
ANSI	American National Standards Institute
ARB	California Air Resources Board
AS	Ancillary Services
ATRA	Annual Transmission Reliability Assessment
CAISO	California Independent System Operator Corporation
CDA	Customer Data Access
CEC	California Energy Commission
CHP	Combined Heat and Power
CIP	Critical Infrastructure Protection
Commission, or CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DER(s)	Distributed Energy Resource (includes distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies)
DERAC	Distributed Energy Resource Avoided Cost
DERiM	Distributed Energy Resource Interconnection Maps
DERMA	Distributed Energy Resources Memorandum Account
DG	Distributed Generation
DPP	Distribution Planning Process
DPRG	Distribution Planning Review Group
DR	Demand Response
DRP	Distribution Resources Plan
DRP Ruling	Assigned Commissioner Ruling
DRRP	Data Request and Release Process
DSP	Distribution Substation Plan
E3	Energy and Environmental Economics, Inc.
EE	Energy Efficiency

EIR	Electrical Inspection Release
EPIC	Electric Program Investment Charge
ES	Energy Storage
ESPI	Energy Service Provider Interface
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
Final Guidance	Guidance for Section 769 – Distribution Resource Planning, attached to the Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning, (February 6, 2015) (R.14-08-013)
FLISR	Fault Location Isolation and Service Restoration
GHG	Greenhouse Gas
GIS	Geographic Information System
GRC	General Rate Case
GWh	Gigawatt-hours
ICA	Integration Capacity Analysis
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IERP	Integrated Energy Policy Report
IGP	Integrated Grid Project
IR	Infrastructure Replacement
IOU	Investor-Owned Utility
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt-hours
kV	Kilovolts
LCR RFO	Local Capacity Requirements Requests for Offers
LNBM	Locational Net Benefits Methodology
LTPP	Long-Term Procurement Plan
MAIFI	Momentary Average Interruption Frequency Index

MPR	Market Price Referent
MW	Megawatt
MWh	Megawatt-hour
NEC	National Electric Code
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
O&M	Operations and Maintenance
OIR	Order Instituting Rulemaking
PEV	Plug-in Electric Vehicle
PUC	California Public Utilities Code
PRG	Procurement Review Group
PRP	Preferred Resources Pilot
PV	Photovoltaic
RA	Resource Adequacy
RECC	Real Economic Carrying Charge
RFO	Request for Offer
RPS	Renewables Portfolio Standard
Rule 21	Rule 21 Electric Tariffs
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison Company
SGIP	Self-Generation Incentive Program
SONGS	San Onofre Nuclear Generating Station
TOU	Time-of-Use
TPP	Transmission Planning Process
TSP	Transmission Substation Plan

T&D	Transmission and Distribution
UL	Underwriters Laboratories
V1G	Managed charging (unidirectional)
V2G	Bi-directional power flow
VGI	Vehicle-Grid Integration
VAR	Volt-Ampere Reactive
WDAT	Wholesale Distribution Access Tariff

Appendix B: Final Guidance and AB 327 Compliance

Final Guidance Requirement	Location in SCE's DRP
1. Integration Capacity and Locational Value Analysis: This section directs the Utilities to develop three analytical frameworks related to the grid integration capacity of DER, the quantification of DER locational value, and the future growth of DERs. The intent being to create a set of mutually supportive tools that at once detail how much DER can be deployed under a business as usual grid investment trajectory, while building the capabilities to compare portfolios of DERs as alternatives to traditional grid infrastructure. In recognition of the fact that the Utilities have started elements of this work already, they are directed to take into account work they have previously conducted, or are currently working on, through their Smart Grid Deployment Plans and their EPIC Investment Plans.	
a) Integration Capacity Analysis (ICA): This analysis will specify how much DER hosting capacity may be available on the distribution network. Worksheets should be provided by the Utilities that show evaluation of available capacity down to the line section or node level. One of the goals of this analysis is to improve the efficiency of the grid interconnection process through coordination between this work product and each Utility's Rule 21 interconnection, Rule 15 main extensions and Rule 16 service connection study processes. To implement this analysis, the Utilities shall do the following in their DRP filings:	Chapter 2, Section B Appendix I: Integration Capacity Analysis Worksheets
i) Perform a distribution system Integration Capacity Analysis down to the line section or node level, utilizing a common methodology across all Utilities. This analysis quantifies the capability of the system to integrate DER within thermal ratings, protection system limits and power quality and safety standards of existing equipment. Results of the analysis are to be published via online maps maintained by each Utility and available to the public.	Chapter 2, Section B, Subsections 3 and 7
ii) Perform an analysis that assesses current system capability together with any planned investments within a 2 year period. Clearly articulate the assumptions and methodology used for load and DER forecasts over the 2 year period.	Chapter 2, Section B, Subsection 6
iii) Perform an analysis using dynamic modeling methods, which are uniform across all Utilities, and circuit performance data. The analysis shall avoid the use of heuristic approaches where possible.	Chapter 2, Section B, Subsections 3
iv) Assess the state of DER deployment and DER deployment projections. For each of the identified DERs, the Utilities should provide current levels of deployment territory wide, plus an assessment of geographic dispersion with circuits that exhibit high levels of penetration identified.	Chapter 2, Section B, Subsection 2
v) If a Utility is unable to conduct dynamic analyses for all feeders down to the line section or node, as an initial phase the Utility shall conduct an integration capacity analysis on a select set of representative circuits, including all related line sections. Utilities shall agree, as necessary, on the methodology used to select the representative circuits. The Utilities must include their methodology for selecting representative circuits as part of this analysis.	Chapter 2, Section B, Subsections 4
vi) Specify a process for regularly updating the Integration Capacity Analysis to reflect current conditions. The process in place for updating the Renewable Auction Mechanism monthly is a good starting point. Where current Utility capabilities are inadequate to conduct a dynamic, line section -level integration capacity analysis, specify a plan for developing these capabilities, including a schedule.	Chapter 2, Section B, Subsection 8
vii) Specify recommendations for utilizing the Integration Capacity Analysis to support planning and streamlining of Rule 21 for distributed generation and Rule 15 and Rule 16 assessments of EV load grid impacts, with a particular focus on developing new or improved 'Fast Track' standards.	Chapter 2, Section B, Subsection 9

b) **Optimal Location Benefit Analysis:** This analysis will specify the net benefit that DERs can provide in a given location. To implement this analysis, the Utilities shall develop the following and file as part of their DRPs:	Chapter 2, Section C
i) A unified locational net benefits methodology consistent across all three Utilities that is based on the Commission approved E3 Cost-Effectiveness Calculator, but enhanced to explicitly include location-specific values, and at minimum include the following value components:	Chapter 2, Section C, Subsection 2
1. Avoided Sub-transmission, Substation and Feeder Capital and Operating Expenditures	Chapter 2, Section C, Subsection 3e
2. Avoided Distribution Voltage and Power Quality Capital and Operating	Chapter 2, Section C, Subsection 3f
3. Expenditures Distribution Reliability and Resiliency Capital and Operating Expenditures	Chapter 2, Section C, Subsection 3g
4. Avoided Transmission Capital and Operating Expenditures:	Chapter 2, Section C, Subsection 3e
5. Avoided RA purchases -- to include system, local and flexible RA (where applicable)	Chapter 2, Section C, Subsection 3c
6. Avoided Renewables Integration Costs	Chapter 2, Section C, Subsection 3j
7. Avoided societal costs clearly linked to DER deployment	Chapter 2, Section C, Subsection 3k
8. Avoided public safety costs clearly linked to DER deployment	Chapter 2, Section C, Subsection 3l
9. Definition for each of the value components included in the locational benefits analysis	Chapter 2, Section C, Subsection 3
10. Definition of methodology used to assess benefits and costs of each value component explicitly outlined above,	Chapter 2, Section C, Subsection 3
11. Description of how a locational benefits methodology can be integrated into long-term planning initiatives like the TPP, LTPP, and the IEPR	Chapter 2, Section C, Subsection 6
ii) Maintenance and Updates to Locations Analysis: A process for maintaining on-going updates to the DER Integration Capacity Analysis and the Optimal Location Benefits Analysis	Chapter 2, Section B, Subsection 9a Chapter 2, Section C, Subsection 5
c) **DER Growth Scenarios:** Utilities shall develop three 10-year scenarios that project expected growth of DERs through 2025, including expected geographic dispersion at the distribution feeder level and impacts on distribution planning.	Chapter 2, Section D Chapter 2, Section D, Subsection 4 and 5 Appendix J: DER Growth Scenarios Worksheets
i) Scenario 1: Adapts the IEPR "Trajectory" case for DER deployment for distribution planning at the feeder lever, down to each line section	Chapter 2, Section D, Subsection 3a and Subsection 4
ii) Scenario 2: Adapts the IEPR "High Growth" case for DER adoption but also incorporates additional information from Load Serving Entities (LSEs), 3rd party DER owners, and DER vendors	Chapter 2, Section D, Subsection 3b and Subsection 4
iii) Scenario 3: Based on very high potential growth in the use of DERs to meet transmission system needs, resource adequacy, distribution reliability, resiliency, and long-term greenhouse gas (GHG) reductions, with key inputs drawn from achieving goals such as the Governor's 2030 Energy Policy Goals, ZNE goals, 2030 GHG reductions, Zero Emission Vehicle Action Plan, 2020 Energy Storage Requirements, 5% of peak load demand response goal, Reduction in the cost and frequency of routine outages, Reduction in the cost and improved responsiveness to major or catastrophic events	Chapter 2, Section D, Subsection 3c and Subsection 4

2. **Demonstration and Deployment:** Propose DER-focused demonstration and deployment projects. These projects are intended to demonstrate integration of locational benefits analysis into Utility distribution planning and operations. Where feasible, these demonstration projects should be coordinated with on-going efforts associated with each Utility's smart grid deployment plan and EPIC investment plan.	
a) **Demonstrate Dynamic Integrated Capacity Analysis:** Develop a specification for a demonstration project where the Utilities' Commission-approved Integration Capacity Analysis methodology is applied to all line sections or nodes within a Distribution Planning Area (DPA). The specification should include a detailed implementation schedule.	Chapter 2, Section E, Subsection 3a Appendix D, Section A
b) **Demonstrate the Optimal Location Benefit Analysis Methodology:** Develop a specification for a demonstration project where the Utilities' Commission-approved Optimal Location Benefit Analysis methodology is performed for one DPA, including a detailed implementation schedule. In selecting which DPA to study, the Utilities shall, at minimum, evaluate one near term and one longer term distribution infrastructure project for possible deferral.	Chapter 2, Section E, Subsection 3b Appendix D, Section B
c) **Demonstrate DER Locational Benefits:** Develop a specification for a demonstration project where at least three DER avoided cost categories or services for which only "normative value data" presently exist can validate the ability of DER to achieve net benefits consistent with the Optimal Location Benefit Analysis. The specification should include a detailed implementation schedule. Such a DER demonstration project will either displace or operate in concert with existing infrastructure to provide the defined functions. The demonstration shall also explicitly seek to demonstrate the operations of multiple DER types in concert. This demonstration shall explain how minimum-cost DER portfolios were constructed using locational factors such as load characteristics, customer mix, building characteristics and the like. Use cases shall employ services obtained from customer and/or 3rd party DERs. The project shall specify products and services employed to obtain the avoided costs or net benefits, and shall specify related transaction methods (e.g. contract, tariff, marginal price) by which customer and/or 3rd party DERs will provide services under the demonstrations.	Chapter 2, Section E, Subsection 3c Appendix D, Section C
d) **Demonstrate Distribution Operations at High Penetrations of DERs:** Develop a specification for a demonstration of high DER penetrations that integrates the Utilities' distribution system operations, planning and investment for implementation. This project shall also explicitly seek to demonstrate the operations of multiple DERs in concert, and operational coordination with third-party DER owners/operators/aggregators and as part of this component of the project shall explain how DER portfolios were constructed.	Chapter 2, Section E, Subsection 3d Appendix D, Section D
e) **Demonstrate DER Dispatch to Meet Reliability Needs:** Develop a specification for a demonstration project where the Utility would serve as a distribution system operator of a microgrid where DERs (both third party- and Utility-owned) serve a significant portion of customer load and reliability services. This project shall also explicitly seek to demonstrate the operations of multiple DERs as managed by a dedicated control system, and as part of this component of the project shall explain how DER portfolios were constructed, as well as how they are being dispatched or otherwise managed.	Chapter 2, Section E, Subsection 3e Appendix D, Section E

3. Data Access: Many of the above sections require various amounts and types of data to be transferred between the utilities and third parties. In some cases, the Utilities may "own" (generate or acquire) the data and in some cases the data may be owned or generated by either the customer or the third party. Data sharing involves a mechanism for communicating the data among the Utilities, customers and DER owners/operators. The type of data that will be shared depends necessarily on the proposed use of the data, and what the use of the data enables, by customers, the market, and the Utility. The following types of data have been mentioned by various parties as important to furthering the goals of the DRP process: - **Distribution system characteristics:** Existing distribution characteristics at substation and feeder-level — coincident & non-coincident peaks/ capacity levels/ outage data/ projected investment needs; Electric Vehicle and charging station populations; Existing DG population characteristics; Backup Generator (BUGs) population; Generation production characteristics, associated with intermittent resources; Existing CHP installations - **Distribution Planning Data:** Demographics: household income levels, CARE customers; Customer DG adoption forecasts; Other customer DER adoption forecasts; Distribution Planning load forecasts, based on forecasting scenarios proposed elsewhere in the plan. Given that issues related to accessing customer data have been recently litigated in Commission Decision (D.) 14-05-016, it is prudent for the DRPs to instead focus on addressing data access relating to data not subject to D.14-05-016.	
a) Proposed policy on data sharing	Chapter 3, Section B
i) Types of data that will be shared, including, but not limited to, all data fields referenced herein.	Chapter 3, Section B
ii) Requirements for receiving data from DER owners (DER owners/operators)	Chapter 3, Section C
b) Procedures for data sharing	Chapter 3, Section B, Subsection 3
i) Proposed process for sharing data with customers and DER owners/operators. Where data is deemed to be confidential for competitive or security reasons, an explanation for why data cannot be shared and a proposed alternative to sharing data that still supports goals of DRPs. Where data release is deemed to infringe on customer privacy an explanation for why data release would violate restrictions, and a proposed method for aggregating or anonymizing data so that it may be shared with third parties.	Chapter 3, Section B, Subsection 3a
ii) Proposed method for making this data available in as near real time as possible, subject to existing privacy constraints, with explicit consideration for how third parties can access this data directly, using the ESPI Customer Data Access system.	Chapter 3, Section B, Subsection 3c
iii) Proposed process for sharing market data from DER owners/operators with Utilities, including policies that deal with confidentiality.	Chapter 3, Section C, Subsection 3
c) Grid Conditions Data and Smart Meters	Chapter 3, Section E
i) Process for making public feeder-level grid conditions data, including coincident & non-coincident peaks, capacity levels, outage data, real and reactive power profiles, impedances and transformer thermal and loading histories, and projected investment needs over the following 10 years	Chapter 3, Section E
ii) Description of Utilities' current plans for obtaining data from smart meters, beyond interval billing data, that reflect power quality and other factors.	Chapter 3, Section E
iii) Process for making data from new sources, such as sensor systems, SCADA systems, substation automation systems, available in a form where it can be analyzed and correlated with existing data sources	Chapter 3, Section E
iv) Plan for how Utilities can leverage DER owner/operator data	Chapter 3, Section C, Subsection 2

4. Tariffs and Contracts: The DRPs may "propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives." For the purposes of these DRPs, discussion of new or modified tariffs and contracts should be limited to their applicability in demonstration projects.	
a) Outline all relevant existing tariffs that govern/incent DERs (ex: NEM, EV-TOU, Rule 21).	Chapter 4, Section B
b) Develop recommendations for how locational values could be integrated into the above existing tariffs for DERs.	Chapter 4, Section C
c) Develop recommendations for new services, tariff structures or incentives for DER that could be implemented as part of the above referenced demonstration programs.	Chapter 4, Section D
d) Develop recommendations for further refinements to Interconnection policies that account for locational values.	Chapter 4, Section E
5. Safety Considerations: Although the utilities must comply with applicable safety and reliability standards in the P.U. Code and General Orders, it may be necessary to propose new or modify existing standards in order to accommodate high levels of DER.	
a) Catalog of potential reliability and safety standards that DERs must meet and a process for facilitating compliance with these standards. Are there differing requirements or standards that should be considered for different types of DER?	Chapter 5, Section B
b) Description of how DERs and grid modernization could support higher levels of system reliability and safety (e.g. improved SAIDI/SAIFI, resiliency, improved cybersecurity).	Chapter 5, Section C
c) Description of major safety considerations involving DER equipment on the distribution grid that could be mitigated or obviated by technical changes.	Chapter 5, Section D
d) Description of education and outreach activities by which the Utility plans to inform and engage local permitting authorities on current best practice safety procedures for DER installation, so that local permitting of DER equipment is not outdated, onerous or overly prohibitive or limiting of otherwise safely and soundly designed projects	Chapter 5, Section E
6. Barriers to Deployment: The DRPs shall identify any barriers to deployment of DER as specified in §769 and outlined in Definitions herein. The DRPs shall focus on three categories of barriers: i) Barriers to integration/interconnection of DERs onto the distribution grid, ii) Barriers to limit the ability of a DER to provide benefits; iii) Barriers related to distribution system operational and infrastructure capability to enable DER provision of benefits. Within each of the identified types of barriers, the DRPs shall categorize the barriers statutory, regulatory, grid insight, standards, safety, benefits monetization, or communications.	
a) Barriers to integration/interconnection of DERs onto the distribution grid	Chapter 6, Section A
b) Barriers that limit the ability of a DER to provide benefits	Chapter 6, Section B
c) Barriers related to distribution system operational and infrastructure capability to enable DER provided value related to needed investment in advanced technology such as advanced protection and control systems, telecommunications and sensing.	Chapter 6, Section C

7. DRP Coordination with Utility General Rate Cases: One of the most critical components of the DRP process will be its interface with the Utilities GRCs. As the analytical tools and demonstration projects required of the DRPs come to fruition, the interface with each Utility's GRC should become clearer. That said, it is currently too early to direct the Utilities to integrate any given piece of the DRP in their next GRC filing. Instead, the Utilities shall include a section in their DRPs where they describe what specific actions or investments may be included in their next GRCs as a result of the DRP process.	
a) Utilities shall include a section in their DRPs where they describe what specific actions or investments may be included in their next GRCs as a result of the DRP process.	Chapter 7
8. DRP Coordination with Utility and CEC Load Forecasting: One of the expected outcomes of the DRP process is greater granularity and accuracy in Utility forecasting of DERs impact on load. This improved and more granular load forecasting will most likely be able to provide input to the IEPR forecast. With this in mind, each Utility should describe how the results of the DRP will influence their own internal load forecasting, the CEC's IEPR load forecast and by extension the Commission's LTPP and the CAISO's TPP.	
a) Each Utility should describe how the results of the DRP will influence their own internal load forecasting, the CEC's IEPR load forecast and by extension the Commission's LTPP and the CAISO's TPP.	Chapter 8, Section B
9. Phasing of Next Steps: The DRPs are likely only to be effective if they serve as the starting point in an on-going effort to integrate DERs into distribution planning, operations and investment. With this in mind, the DRP process should be a living one, where the Commission, the Utilities and stakeholders engage continuously to refine the activities and goals that are central to the DRPs themselves. Although §769 appears to call for a one-time exercise in this new method of Distribution Planning, there appears to be general agreement that this should really be an on-going, cyclical process that will repeat over time to incorporate how technologies and market policies are evolving and to take advantage of lessons learned in previous cycles. For this reason, the Utilities shall include in their DRPs a plan for how their DRPs can be updated on a biennial filing cycle.	
a) Utilities shall include in their DRPs a plan for how their DRPs can be updated on a biennial filing cycle. Included in this component of the DRPs shall be a proposal for rolling updates to the DRPs occurring at least every two years for the next ten years, including a clear mapping of how these subsequent DRP phases will interact with each Utility's GRC, as well as other funding authorizations, like Commission Energy Efficiency Programs.	Chapter 8, Section C
b) Utilities shall include a proposal that either adopts, or adopts with amendments, the following set of recommendations: Phase 1 (2 years, 2016-2017); Phase 2a (2 years, 2018-2019); Phase 2b (Ongoing, 2018 and Beyond). (Note: Detailed set of recommendations can be found on page 12-13 of the Final Guidance.)	Chapter 8, Section D

AB327 - DRP Guidance	Location in SCE's DRP
SEC. 8. Section 769(b) is added to the Public Utilities Code, to read: (b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:	**Application Chapters 1-8**
(1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.	Chapter 2
(1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.	Chapter 2
(2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost effective distributed resources that satisfy distribution planning objectives.	Chapter 4
(3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.	Chapter 2 Chapter 4
(4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.	Chapter 7
(5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.	Chapter 5 Chapter 6

Appendix C: 30 Representative Distribution Circuits

The table below identifies the 30 representative distribution circuits that were used to conduct SCE's Integration Capacity Analysis.

Circuit	Voltage (kV)	Circuit Miles (Mi)
Armona	4 kV	3.4
Caldwell	12 kV	5.5
Cawston	4 kV	3.5
Diana	12 kV	8.3
Doerner	12 kV	7.6
Drive Inn	12 kV	12.0
Etting	16 kV	4.0
Hammock	33 kV	29.8
Homer	12 kV	11.9
Joshua	12 kV	7.3
Kneeland	4 kV	0.7
Lauterbach	4 kV	1.9
Libra	16 kV	6.9
Lynx	12 kV	2.6
Major	4 kV	2.6
Mallet	12 kV	9.5
Miles	4 kV	3.2
Miracle City	5 kV	2.6
Mirror	12 kV	10.3
Moran	12 kV	12.7
Parrot	12 kV	7.7
Price	12 kV	8.6
Rossi	12 kV	6.8
Smoke Tree	12 kV	6.7
Solitaire	12 kV	9.2
Soto	12 kV	9.5
Tamarind	12 kV	8.3
Wasp	16 kV	14.2
Wildwood	16 kV	6.5
Woodhaven	16 kV	6.6

Appendix D: Specifications for Demonstration and Deployment Projects

A. Demonstration of the Integration Capacity Analysis (Demonstration A)

	Description
Background	Pursuant to the Final Guidance, "this demonstration shall utilize fully dynamic modeling techniques for all lines sections or nodes within the selected Distribution Planning Area (DPA)" (ICA Demonstration). Then, the demonstration should consider, at a minimum, the following two scenarios: (1) the DER capacity does not cause power to flow beyond the substation busbar (no reverse power flow) and (2) the DER technical maximum capacity is considered irrespective of power flow toward the transmission system. This study will be completed utilizing dynamic modeling techniques via power system modeling software (e.g., CYME, PSLF), and will not include a field demonstration. The DPA SCE intends to study will be served by an "A" level substation, which consists of multiple distribution substations with multiple circuits (or feeders) in the Orange County area of the SCE service territory (within the PRP project area). The power system modeling software will allow SCE to perform an Integration Capacity Analysis (ICA) using dynamic modeling methods for every feeder (and its respective line segments) within the DPA. Software will also be used to assess the impact of DERs producing to the grid under the two scenarios described above. The demonstration will evaluate the impact of increased levels of DERs on the electrical grid.
Specifications	1. Assess the aggregate effect to the electrical grid when DERs are interconnected across several distribution circuits served out of multiple distribution substations and when there is no reverse power flow through the distribution substation transformers (Scenario 1). • Generation will be increased up to the hosting capacity for each distribution circuit, but just prior to the aggregate generation reversing power flow through the distribution substation transformers. This analysis will provide an understanding of the impacts to distribution circuits and distribution substations due to increased levels of DERs. 2. Assess the aggregate effect to the electrical grid when DERs are interconnected across several circuits out of multiple distribution substations and when there is reverse flow power into the subtransmission system and towards the transmission system (Scenario 2). • Generation will be increased up to the hosting capacity for each distribution circuit, so that the aggregate generation reverses power flow through the distribution substation transformers for multiple distribution substations. This analysis will provide an understanding of the impacts to the electrical grid due to reverse power flow from distribution circuits.
Implementation Schedule	The Final Guidance requires that this "demonstration project shall be scoped to commence no later than 6 months after commission approval." SCE intends to commence the ICA Demonstration one month after Commission approval of the DRP. Details of this schedule can be seen in Table D-1 on the next page.
Deliverable	SCE intends to have a report finalized approximately 12 months after Commission approval of the DRP. At completion of the project, a final report will communicate the findings and recommendations to inform future iterations of the ICA and to provide other recommendations that could support operation of the system during the conditions studied.

Table D-1 Demonstration A Implementation Schedule

Demo A: Dynamic Integrated Capacity Analysis																	
Line Item	Milestone	2015				2016				2017				2018			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	**Commence Project** - Begin Pre-Study work which includes power system model validation and development																
2	**Conduct Studies and Document Findings** - Perform an ICA for each distribution circuit within the DPA using dynamic modeling methods - Asses the potential impacts to the distribution grid for each scenario - Document findings from studies																
3	**Prepare Report**																
4	**Submit Final Report to CPUC**																

B. Demonstration of the Optimal Location Benefit Analysis (Demonstration B)

	Description
Background	Pursuant to the Final Guidance, SCE is required to develop a specification for a project to demonstrate the Commission approved Optimal Location Benefit Analysis Methodology (LNBM Demonstration). Pursuant to Final Guidance Requirement No. 1.b, SCE proposed a locational net benefits methodology (LNBM) as part of Chapter 2 of the DRP. This project will be a study to demonstrate the LNBM and will not include a field demonstration. The LNBM is based on E3's Distributed Energy Resource Avoided Cost (DERAC) tool and includes components such as generation energy, T&D losses, generation capacity, T&D capacity investment deferral, and other components. In this demonstration, SCE will calculate the T&D capacity investment deferral on two distribution infrastructure projects, one near-term (0-3 year lead time) and one longer-term (3 or more years lead time) within the same distribution planning area (DPA).
Specifications	1. Demonstrate use of the LNBM in the SCE distribution planning process for identification of projects for evaluation. • Identify two potential projects for deferral, one near-term and one longer-term. • Calculate the T&D capacity investment deferral on the two projects. 2. Construct DER portfolios that can help meet the grid needs. • Assess the capability of different sample portfolios of DERs. 3. Apply the LNBM. • Apply the LNBM to the sample DER portfolios. 4. Assess any potential timing considerations. • Given that one project is near-term and the other is longer-term, SCE will evaluate the potential timing considerations associated with pursuing and ensuring DERs would be operational within the needed timeframe.
Implementation Schedule	The Final Guidance requires that "Demonstration project shall be scoped to commence no later than one year after commission approval." SCE intends to commence the LNBM Demonstration one month after Commission approval of the DRP. Details of this schedule can be seen in Table D-2 on the next page.
Deliverable	SCE intends to have a report finalized approximately 12 months after Commission approval of the DRP. At completion of the project, a final report will communicate the results of the comparison, identify lessons learned, and recommend ways to refine the LNBM.

Table D-2 Demonstration B Implementation Schedule

Demo B: Optimal Location Benefit Analysis Methodology																	
Line Item	Milestone	2015				2016				2017				2018			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	**Commence Project** - Identify one near-term and one longer term project for consideration located within one DPA						■										
2	**Conduct Studies** - Determine system requirements associated with infrastructure projects and construct DER portfolios that can meet system requirements - Develop price forecasts and scenarios and calculate deferral value for the two projects located within the DPA						■	■									
3	**Assessment** - Calculate the net present value of future benefits minus future costs for the DER projects and the distribution infrastructure projects - Consider qualitative factors in the LNBM								■								
4	**Prepare Report**									■							
5	**Submit Final Report to CPUC**									■							

C. Demonstration of DER Locational Benefits (Demonstration C)

	Description
Background	Pursuant to the Final Guidance, SCE is required to develop a specification for a project to demonstrate the "ability of DER to achieve net benefits consistent with the Optimal Location Benefit Analysis" (LNBM Field Demonstration). SCE will be leveraging its PRP activities. All or a portion of the PRP area will serve as the location of Demonstration C. SCE will design DER portfolio options that can meet the expected load growth in the PRP target area and will seek to acquire them in a timely manner in order to conduct field demonstrations to test DERs ability to achieve net benefits consistent with the Optimal Location Benefits Analysis. SCE assumes that the term "Optimal Location Benefit Analysis" is synonymous with the LNBM. SCE selected the PRP region as the demonstration project to test locational benefits because it is an area pre-identified with a transmission constraint that could be resolved through the addition of gas-fired generation, transmission upgrades or, alternatively, through the use of DERs. In addition to being an area where SCE is seeking to expedite the deployment of DERs, it is an area where SCE is developing the next generation of grid infrastructure to manage, operate, and optimize DERs. SCE proposes that as, part of this DRP demonstration project, SCE may determine that it would need to make and fund system upgrades that are necessary to accommodate sufficient DER penetration in the area, in a safe and reliable manner.
Specifications	1. Identify the optimal location(s) within the PRP region where at least three DER avoided cost categories or services for which only "normative value data" could validate the ability of DER to achieve net benefits consistent with the Optimal Location Benefit Analysis. i. The optimal location(s) will be determined by the ability to deploy DERs to avoid DER cost categories or services. 2. Design proposed solutions to meet the locational needs in terms of grid infrastructure upgrades and DER acquisition. i. Specifically for grid infrastructure needs, Demonstration C will: ▪ Leverage analysis associated with SCE's smart grid deployment and EPIC investment plan. ▪ Determine if DERs can safely and reliably operate in concert with existing infrastructure to provide the defined functions. ▪ Determine if distribution grid investments are needed to facilitate a higher penetration of DERs for Demonstration Project purposes; if upgrades are needed, the scope of work will be identified. ii. Specifically for DER needs, Demonstration C will: ▪ Determine the energy attributes that need to be met by the DERs. ▪ Obtain and aggregate input from Load Serving Entities, customers, third-party DER providers and DER technology vendors to identify portfolio options to serve the locational needs and identify data exchange barriers. ▪ Develop a spectrum of portfolios consisting of multiple DERs using locational factors such as load characteristics, customer mix, building characteristics and the like. ▪ Design a DER acquisition plan, including optimal transaction methods (e.g. contract, tariff, marginal price) by which customer and/or 3rd party DERs will provide services under the demonstrations.

	Description
Specifications	3. Implement the DER acquisition plan and, as applicable, distribution grid upgrades i. For DER acquisition, Demonstration C will ▪ Acquire DERs through SCE's existing demand side management (DSM) programs and competitive solicitations • Where allowed, DSM programs will be enhanced to increase customer adoption rate for the locational benefit • Where feasible, SCE will leverage existing RFOs to acquire DERs in the right locations, and use pre-established cost recovery mechanisms ▪ As needed, SCE will implement DER and location specific RFOs, and seek cost recovery for such contracts through regulatory filing(s). ▪ Through its acquisition sources, SCE will seek to install DERs in a manner that allows for demonstration of the operations of multiple DER types in concert (e.g., pairing of PV and energy storage). ii. Implement distribution grid upgrades, if needed. 4. Operate DERs discretely and in concert to demonstrate if DERs can achieve optimal locational benefits. i. Confirm multiple DERs, combined with needed grid upgrades, can operate in concert to achieve safe and reliable operations of the grid. 5. Evaluate and analyze results to validate DERs ability to achieve optimal locational benefits i. Determine DERs ability to achieve optimal locational benefits. ▪ Evaluate the ability of DERs and grid system changes (if any) to achieve net benefits consistent with the Optimal Location Benefit Analysis. ▪ Evaluate the effectiveness of DERs to inform the distribution planning process and inform the selection between DER or system investments.
Implementation Schedule	The Final Guidance requires that this "[d]emonstration project shall be scoped to commence no later than one year after Commission approval." This project is scoped to commence within 12 months after Commission approval. Since this demonstration project is building on work currently in progress in the PRP target area, within 1 month after Commission approval of the DRP, SCE will begin evaluation of the existing demonstration plan and adjust accordingly to incorporate the Commission approval of the DRP. Details of this schedule can be seen in Table D-3 on the next page.
Deliverable	SCE expects to complete this demonstration project approximately 3 years after Commission approval of the DRP. A report communicating the findings and recommendations on the ability of DERs to provide net locational benefits, and to inform future iterations of the LNBM and provide other recommendations that could support operation of the system during the conditions studied.

Table D-3 Demonstration C Implementation Schedule

Demo C: DER Locational Benefits																					
Line Item	Milestone	2015				2016				2017				2018				2019			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	**Implementing PRP's DER Acquisition Plan** - Acquisition actives consists of leveraging SCE's DSM programs, existing solicitations, and implementing location/resource specific solicitations	■	■	■	■	■	■														
2	**Study to determine if Grid Infrastructure Solutions are necessary** - Any needed solutions will be based on accommodating the needs of the demonstration project in a safe and reliable manner			■	■	■	■														
3	**Adjust Scope of Demonstration Project Based on CPUC's DRP Ruling** - Inputs to location selection, DER solutions, timing, and analysis will be adjusted based on CPUC's final ruling -Confirm optimal location(s) for demonstration project. Locations will be determined by ability to deploy DER to avoid DER cost categories or services							■	■												
4	**Adjust and Implement the DER Acquisition Plan** - Lessons learned and new market barrier solutions will be incorporated to acquisition plan to enable higher penetration of DERs								■	■	■	■	■	■	■	■	■				
5	**Implement Grid Infrastructure Solutions** - Implement grid infrastructure solutions needed in a timely manner to accommodate demonstration project needs								■	■	■	■									
6	**Operate DERs** - Confirm multiple DERs, combined with needed grid upgrades, can operate in concert to achieve safe and reliable operations of the grid							■	■	■	■	■	■	■	■	■	■				
7	**Evaluate and Validate the Results** - Evaluate the ability of DERs and grid system changes (if any) to achieve net benefits consistent with the Optimal Location Benefit Analysis and inform the distribution planning process with regards to selection between DER or system investments																	■	■	■	
8	**Submit Update Report to CPUC** - As part of DRP Filing										■								■		
9	**Submit Final Report to CPUC** - Submit final report at completion																				■

Note: PRP activities have occurred prior to 2015 including design of initial DER solutions

D. Demonstration of Distribution Operations at High Penetrations of DER (Demonstration D)

	Description
Background	SCE will conduct a field demonstration in the Integrated Grid Project (IGP) region for Demonstration D (High DER Demonstration) using resources and activities from other SCE projects like the PRP and EPIC-funded Regional Grid Optimization Demonstration.[1] The IGP region is located in south Orange County (within the Preferred Resources Pilot area, described above) at the Joanna Jr. substation. IGP will demonstrate the next generation grid infrastructure to manage, operate, and optimize DERs and will evaluate how high penetration of DER may impact operations and potentially influence planning and investment. This project will work to achieve high penetration of DERs[2] and test advanced automation, enhanced communication networks, and grid-management control systems. The attainment of high penetration will leverage Demonstration C acquisition and grid reinforcement activities. Acquisition is dependent on customer and third party decisions within the region. The goal is to integrate customer and third party DERs with utility assets to optimize the use of the resources in the area. The field demonstration will operate multiple DER devices in concert on up to 5 circuits within the Johanna Jr. substation. Portfolios of DER resources will be assembled and dispatched to show how high penetration of DER can be coordinated on circuits and out of the substation. SCE proposes that as, part of this DRP demonstration project, SCE may determine that it would need to make and fund system upgrades that are necessary to accommodate sufficient DER penetration in the area, in a safe and reliable manner.
Specifications	1. Evaluate co-optimization of customer resources with grid assets. a. Model circuits and evaluate various penetration levels and optimization opportunities. b. Develop control optimization strategies through simulations. c. Employ utility scale storage with customer and third party resources to operate multiple DERs in concert. d. Identify and explain DER portfolio construction. 2. Assess how high penetration impacts on grid operations and in particular switching operations. a. Increase monitoring of resources (generation, storage, and load) to improve situational awareness of circuits. 3. Assess how high penetration of DERs can be operated for grid benefit. a. Use detailed circuit models and field data to better plan distribution system upgrades that may result in upgrade deferral. b. Develop control systems and algorithms to coordinate DERs including third party DERs. c. Evaluate and demonstrate protection methods needed to accommodate high penetrations of DER devices. d. Demonstrate a field area network communications system necessary to

1 The Regional Grid Optimization Demonstration was funded through EPIC in November 2013 (D.13-11-025) and April 2015 (D.15-04-020).

2 Some of the DERs will be owned by SCE, while others will be owned by customers and/or third party aggregators.

	Description
	support high penetration of DERs. e. Demonstrate a voltage regulation control system to integrate distribution capacitor control with DER reactive power output to reduce customer energy usage while maintaining appropriate voltage levels. 4. Assess how high penetration of DERs will influence distribution planning and investments. a. Leverage the field demonstration to inform the distribution planning process and potential benefits from DER and the potential impacts on traditional grid investments. 5. Evaluate data access and exchange methods. a. Significant amounts of data relating to circuit operations and customer/SCE DER performance will be captured. b. Methods will be developed as part of IGP to manage this data. c. Measures will be put in place for customer data to ensure appropriate confidentiality is maintained. Methods to exchange data with third party DER providers will be developed.
Implementation Schedule	As noted within the DRP Guidance, "The Demonstration project shall be scoped to commence no later than 12 month after Commission approval". This project is scoped to commence within 12 months after Commission approval. Aspects of this project are already in progress and funded through the existing EPIC program. Within 12 months after Commission approval of the DRP, SCE will modify any necessary components based upon the Commission approval. Details of this schedule can be seen in Table D-4 on the next page.
Deliverable	SCE expects to complete this demonstration project approximately 2 years after Commission approval of the DRP. Annual reports are provided to the CPUC as a component of the EPIC program for IGP. The deliverable of this demonstration project is an update report as part of future DRP filings as well as a final report at the completion of the project. These reports will summarize key successes and challenges relating to utilization of high DER penetration to provide potential grid benefits (e.g., project deferral), the planning and operational coordination of multiple DERs under high penetration, and effectiveness of solutions tested to support high penetration of DERs.

Table D-4 Demonstration D Implementation Schedule[3]

Line Item	Milestone	2015				2016				2017				2018				2019			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	**Assessment & Study** - Develop cost benefit and a locational value methodologies based on an integrated approach to distribution operations, planning and investment planning.		■	■	■	■	■														
2	**Finalize Conceptual Design** -Select circuits (up to 5); Develop coordination plan with 3rd party Owners, Operators, Aggregators		■	■	■																
3	**Develop Circuit Design & Perform Modeling** - Detailed engineering with DERs; Communications & Controls		■	■	■	■	■														
4	**Develop Technical Specifications for Equipment Procurement** - Control System for coordinated control of DERS, Communications System, Monitoring devices			■	■																
5	**Procure Equipment** - Control System for coordinated control of DERS, Communications system, monitoring devices, etc.			■	■	■															
6	**Procure Utility Owned DERS** - Procure/solicit additional DERs as necessary	■	■	■	■	■	■	■	■												
7	**Lab Test** - Bench test DER control system, communications systems and monitoring devices. Customize as necessary.						■	■	■												
8	**Validate for Field Installation/Acceptance Test** - Simulate the field conditions - Install tool in the field and run field trial tests								■	■											
9	**Site Permitting** - Obtain necessary construction permits					■	■														
10	**Civil & Electrical for Circuit Apparatus and Multiple DERs (Utility Owned and Others)** - Site Civil and electrical construction; Grid upgrades						■	■	■	■	■	■	■	■	■	■	■				
11	**Controls, Communications and Integration** - Control system, network, communications, back-office and integration.							■	■	■	■										
12	**Perform Site Acceptance Test and Release to Operations (Phased)** - Verify the system is functioning as designed; release to SCE operations								■	■	■	■									
13	**Test and Collect Operating Data** - Test the DER control system capabilities on live circuits - Collect operational data (phased as additional DERs are installed)									■	■	■	■	■	■	■	■	■	■	■	
14	**Analyze Data & Results** - Start documentation for demonstration - Complete final demonstration report and route for internal review																		■	■	
15	**Submit Update Report to CPUC** - As part of DRP Filing										■								■		
	Submit Final Report to CPUC - Submit final report at completion																				■

3 The acquisition of third party DERs in support of the High DER Demonstration follows the schedule delineated in Table D-3 Demonstration C Implementation Schedule

E. Demonstration of DER Dispatch to Meet Reliability Needs (Demonstration E)

	Description
Background	This demonstration project is designed to show how a utility could serve as a distribution system operator for a microgrid (Microgrid Demonstration). SCE will use a microgrid, in conjunction with DERs, to support customer load within North Orange County. SCE would manage utility- and customer- or third party developer-owned resources through one or more dedicated control systems. The demonstration project will demonstrate a microgrid to serve a significant portion of customer load and provide reliability services. The demonstration will also explain how the microgrid portfolio was assembled and dispatched to support customer load. SCE will demonstrate how a grouping of loads, generation, and storage can be utilized as part of a demonstration of a microgrid. The operation of the available resources will be coordinated through a dedicated control system managed by SCE. The demonstration project will also provide details explaining the development of DER portfolios needed to support customer load as part of the microgrid. SCE is currently in discussions with multiple customers (e.g., military facilities, campuses) to gauge their interest in participation in a microgrid. Due to differing customer needs, which play a role in the magnitude and portfolio of resources required, SCE has started the process of interacting with customers. Once the needs of the microgrid have been finalized, and a firm commitment has been received, SCE plans to identify the specific project location by the start of the demonstration project. SCE does not know at this time if and what kind of funding may be required to support the project. SCE proposes that it would record the revenue requirement associated with incremental costs for this demonstration project into the proposed DERMA.
Specifications	1. Establish customer requirements for a microgrid and obtain commitment and partnership from customer(s) and seek collaboration with third parties. a. Planned for completion prior to commission approval of DRP. 2. Identify how multiple Third Party and Utility-owned DER resources could be operated in a coordinated manner to support operational needs a. Customer/third party- and utility-owned resources will be coordinated through the use of a high-speed communications and control system to match loads and resources on that circuit segment. 3. Identify how multiple Customer/Third Party and Utility-owned DER resources could maintain or improve grid reliability a. Use of resources on a circuit segment can help control circuit peak loads, and assist with voltage regulation. 4. Assess needs and effectiveness of management system in the coordination of available DER. a. Additional monitoring points will improve situational awareness needed to balance load and generation as well as manage variability. b. The dispatch of resources will be coordinated by a dedicated control system and validated through the monitoring points. 5. Identify concerns related to data access or exchange. a. Methods to exchange data with 3rd party DER providers will be developed.
Implementation Schedule	As noted within the DRP Guidance, "The Demonstration project shall be scoped to commence no later than 12 months after commission approval." SCE intends to comply with this requirement and ensure that this project will commence within one year after approval of this DRP. Details of this schedule can be seen in Table D-5 on the next page.

	Description
Deliverable	SCE expects to complete this demonstration project approximately 3 years after Commission approval of the DRP. Update reports will be submitted as part of future DRP filings, and a final report will be submitted at the completion of the project. Reports will summarize key successes and challenges and the overall effectiveness of solutions within the demonstration.

Table D-5 Demonstration E Implementation Schedule

Line Item	Milestone	2015				2016				2017				2018				2019			
	Demo E: DER Dispatch to Meet Reliability Needs	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	**Conceptualize the Scope & Location** -Identify and finalize the demo location & obtain stakeholder buy-in																				
2	**Develop the Scope & Complete Engineering** - Perform pre-engineering; Initiate the design process																				
3	**Start and Complete the Design** - Drafting and Modeling																				
4	**Validate the Control Tool** - Identify and obtain the control algorithm/system to provide microgrid with "islanding" capabilities																				
5	**Perform Lab Testing** - Complete lab testing and customize the tool to meet project specific needs)																				
6	**Start validation for Field Installation** - Simulate the field conditions - Install control system in the field and run field trial tests																				
7	**Permits** - Obtain Permits, Licenses, and align with third parties within the demo region																				
8	**Civil** - Begin and complete civil construction, conduits, walls, pads etc.																				
9	**Electrical** - Begin and complete electrical construction																				
10	**Test and Release to Operations** - Verify the system is functioning as designed; release to SCE operations																				
11	**Conduct Testing** - Test the Microgrid capabilities on live circuit : islanding, synchronization, etc.																				
12	**Confirm and Conform Test Results** - Evaluate the test results & modify the system as required																				
13	**Evaluate and Validate the Results** - Perform final test, Start documentation for demonstration																				
14	**Final Demonstration Report** - Complete final report and route internal for approval and submitted to CPUC)																				
15	**Submit Update Report to CPUC** - As part of DRP Filing																				
	Submit Final Report to CPUC - Submit final report at completion																				

Appendix E: Distribution Circuits with High Levels of DG Penetration

The Distributed Renewable Generation and the Energy Storage demand values are from an SCE internal database used for planning of the Distribution System. The table below contains the top 1% of Distributed Generation interconnected circuits.

Sub	Circuit	Voltage	DG (MW)
Garnet	Tram	33.0	33.8
Casa Diablo	Vulcan	33.0	32.0
Garnet	Pierson	33.0	29.0
Garnet	Townhall	33.0	28.4
Blythe City	Chanslor	33.0	27.2
Garnet	Coachella	33.0	24.6
Victor	Russ Boyd	33.0	22.5
Hi Desert	Santana	33.0	20.3
Victor	Old Trails	33.0	20.0
Hi Desert	Himo	33.0	18.5
Gale	Luz	33.0	14.7
Estero	Greenhouse	16.0	13.2
Northwind	Gust	12.0	13.1
Oasis	Hanger	12.0	12.3
Crater	Rhoda	16.0	12.3
Narrows	Cadillac	12.0	12.3
Del Sur	Pronghorn	12.0	11.6
Inyokern	Rickover	33.0	11.1
Sullivan	Yuma	12.0	10.6
Brea	Acapulco	12.0	10.5
San Antonio	Rock	12.0	10.2
Goldtown	Discovery	12.0	10.1
Alessandro	Oliver	33.0	9.9
Del Sur	Snowden	12.0	9.7
Elizabeth Lake	Guitar	16.0	9.3
Hi Desert	Sheephole	33.0	9.0
Northwind	Pinwheel	12.0	8.7
Cabrillo	La Salle	12.0	8.3
Neptune	Drift	12.0	8.1
Lancaster	Oban	12.0	8.0
Bunker	Chaney	12.0	8.0
Del Sur	Lloyd	12.0	8.0
Lindsay	Cairns	12.0	7.8
Monolith	Keene	12.0	7.8
Archibald	Hofer	12.0	7.8
Lancaster	Crowder	12.0	7.6
Alhambra	Marguerita	16.0	7.5
Ellis	Darwin	12.0	7.5

Appendix F: Applicable Data Privacy and Confidentiality Laws and Rules

Law or Decision	Summary
Commission Decisions	
D.91-05-007	• CHP efficiency information is confidential indefinitely under CPUC D.91-05-007; • D.91-05-007 OP 3 states, "SDG&E, PG&E, and Edison shall not permit any person who is not charged with monitoring power producer operating efficiencies to gain access to power producers' operating data. SDG&E, PG&E and Edison shall not permit any employee of any utility affiliate to gain access to power producers' operating data." • See also D.91-05-007, Conclusion of Law 8, which states: "The utilities should assure that their employees who have access to power procurers' operating data do not disclose that information to any party who is not charged with monitoring power producers' operating efficiencies or to any employee of a utility affiliate engaged in unregulated power production."
D.97-10-031	• Adopted by the Commission in the Direct Access Proceeding • The 15/15 Rule requires that any aggregated information provided by SCE must be made up of at least 15 customers and a single customer's load must be less than 15% of an assigned category. • If the number of customers in the complied data is below 15, or if a single customer's load is more than 15% of the total data, categories must be combined before the information is released. • If the 15/15 Rule is triggered for a second time after the data has been screened once already using the 15/15 Rule, the customer should be dropped from the information provided.
D.01-07-032	• D.01-07-032 denied California Narcotics Officers Association access to utility customer information without a subpoena and customer notice; • When utility customer data is provided to law enforcement agencies without legal process, the customers' privacy rights under Article I, §13 of the California Constitution are violated.
PUC §§ 454.5(g), 583. D.06-06-066 (modified by D.07-05-032), D.08-04-023 and D.06-12-030 (modified by D.11-07-028) – Access to Market Sensitive Procurement Information	• D.06-06-066 (modified by D.07-05-032) adopted a process for determination of whether information is entitled to confidential treatment as "market sensitive" for purposes of § 454.5(g); includes a matrix of market sensitive procurement data and rules for providing access to it; • D.08-04-023, D.06-12-030, D.11-07-028 include rules for accessing procurement data, including form model protective order and non-disclosure agreement
PUC § 8380 *et seq.* D.11-07-056, D.12-08-045, & D.13-09-025 – Smart Grid Data Privacy	• Allows customers to authorize third parties to automatically access their Smart Meter hourly usage data, directly from the utility data servers. • Adopts privacy rules that apply to customer energy data collected from Smart Meters • Provides for collection of "covered information" for "primary purposes" only. "Secondary purposes" require customer consent. • D.12-08-045 established privacy protections concerning customer usage data for customers of gas utilities, community choice aggregators (CCAs), and electric service providers (ESPs) similar to those established in D.11-07-056 for electric utility customer data. • D.13-09-025 adopted process for oversight of third parties who are accessing customer data by participating in the program. Creates a website list of third parties ineligible due to past abuses.

PUC § 8380 *et seq.* D.97-0-031; D.14-05-016 – Rules to Provide Access to Energy Usage Data While Protecting Privacy of Personal Data	• Requires IOUs to post aggregated customer usage data by zip code and customer class (i.e., residential, commercial, industrial, agriculture). • Requires IOUs to provide specified customer data to local governments, research institutes, and state and federal agencies for specific purposes through data requests • Adopts aggregation methods for customer energy usage data by customer class against the background of the general 15/15 rule and smart grid privacy rules
Federal Rules, Laws, and Industry Standards	
North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP)/ FERC Order Nos. 706, 761	• NERC/CIP is a set of requirements (part of the NERC Reliability Standards) designed to secure the assets required for operating the U.S. bulk electric system. It consists of 11 standards (each with multiple requirements) covering the security of electronic perimeters and the protection of critical cyber assets as well as personnel and training, security management, disaster recovery planning, cyber security and physical security. They require entities to identify critical assets and to perform ongoing risk analyses of those assets, create specific policies governing access to those assets, use firewalls and cyber-attack monitoring tools, enforce IT controls and have comprehensive contingency plans for cyber and physical attacks. • CIP-011 (Cyber Security — Information Protection) is aimed at preventing unauthorized access to BES Cyber System Information by specifying information protection requirements in support of protecting BES Cyber Systems against compromise that could lead to improper operation or instability in the BES.
Critical Energy Infrastructure Information (CEII) FERC Order Nos. Order Nos. 702, 630, 630-A, 643, 649 and 683.	• CEII is specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that: 1) Relates details about the production, generation, transmission, or distribution of energy; 2) Could be useful to a person planning an attack on critical infrastructure; 3) Is exempt from mandatory disclosure under the Freedom of Information Act; and 4) Gives strategic information beyond the location of the critical infrastructure.
Critical Infrastructure Information Act of 2002, 6 U.S.C. §§ 131 – 134.	• Information relating to critical infrastructure and protected systems. Protected Critical Infrastructure Information (PCII) typically includes information described as CEII or NERC CIP Protected Information. • Qualifying information submitted to, and deemed to be PCII by, the U.S. Department of Homeland Security, is exempt from disclosure under the Freedom of Information Act and other disclosure laws.
Commission General Orders	
Section 2.2(b) General Order 66-C	• Establishes items that are excluded from the term "public records of the Public Utilities Commission. • Such expressly excluded documents includes records or information precluded from disclosure by statute (e.g., accident reports); confidential information required by the Commission requested by the Commission, which, if revealed, would place a utility at an unfair business disadvantage, certain personnel records, etc.
State Laws	
California Evidence Code §1060	• Shields "trade secrets" from public disclosure. • "Trade secrets" include any "information, including a formula, pattern, compilation, program, device, method, technique, or process, that: (1) [d]erives independent economic value, actual or potential, from not being generally known to the public or to other persons who could obtain economic value from its disclosure or use; and (2) [i]s the subject of efforts that are reasonable under the circumstances to maintain its secrecy."

California Civil Code § 1798.81.5	• Requires a person or business that conducts business in CA, and that owns or licenses computerized (electronic) data that includes personal information, to disclose a security breach upon discovery of the breach. • Requires such person or business to provide notification of the breach in the security of the data to a resident of California whose unencrypted personal information was, or is reasonably believed to have been, acquired by an unauthorized person. Such disclosure must be made in the most expedient time possible and without unreasonable delay. • Requires a person or business that maintains computerized (electronic) data that includes personal information, but which the person or business does not own, to notify the owner or licensee of the information of the breach of the security of the data immediately following discovery of the breach, if the personal information was, or is reasonably believed to have been, acquired by an unauthorized person. • The notification required by this section shall be made promptly after the applicable law enforcement agency determines that such notification will not compromise its investigation. • Provides specific requirements for the form of the security breach notification. • A person or business that is required to issue a security breach notification pursuant to this section to more than 500 California residents as a result of a single breach shall electronically submit a single sample copy of that security breach notification, excluding any personally identifiable information, to the Attorney General.
California Public Records Act, Cal. Gov. Code §§ 6250 – 6276.48	• Critical infrastructure information voluntarily submitted to the California Emergency Management Agency is withheld from disclosure under California's Public Records Act. Section 6254(ab) • Other information where the public interest served by not making the record public clearly outweighs the public interest served by disclosure of the record. Section 6254.
Senate Bill 699	• Requires the CPUC to adopt inspection, maintenance, repair, and replacement standards, and adopt rules to address security threats, for the distribution systems of electrical corporations • The CPUC issued a staff paper on February 11, 2015. The staff paper recommended that the Commission open a Rulemaking to evaluate and update existing requirements regarding physical security of the electric system, in a manner consistent with SB 699. This includes appropriate confidentiality measures for sensitive, security-related information.

Appendix G: Proposed Data Access Policy and Workshop Issues

Data Type Identified in Final Guidance	Description/SCE Policy	Issues for Workshops
Non-coincident peak at substation/ feeder level	Description: • The forecasted peak load for a circuit or substation can be obtained by clicking on a circuit or substation. SCE Policy: • Provide through DERiM	• Discuss if non-coincident peak displayed on DERiM meets third parties' needs
Capacity levels at substation/feeder level	Description: • 15% generation capacity, and maximum achievable capacity will be presented at the circuit level. Integration capacity (See Chapter 2) will be presented at the line section level. SCE Policy: • Provide through DERiM	• Discuss if capacity displayed on DERiM meets third parties' needs
Existing DG population characteristics	Description: • Existing generation, queued generation, total generation, and current penetration level will be displayed at the circuit and substation levels on DERiM. • California Solar Initiative program data, including individual project costs, incentives, size, and other data available on website below SCE Policy: • Provide through DERiM • CSI data available on www.californiasolarstatistics.ca.gov	• Discuss if DG population displayed on DERiM and California Solar Statistics meets third parties' needs
Outage data at Substation/feeder level	Description: • System reliability reports (System Average Interruption Duration Index, System Average Interruption Frequency Index, Momentary Average Interruption Frequency Index) provided by county, city, and circuits • Reliability history • Capital improvement plan by city • Planned Outages SCE Policy • Data at different granularity already provided publicly • Determine at workshops if existing data meets third party needs • https://www.sce.com/wps/portal/home/outage-center/reliability-reports	• Determine whether data at county, city, and circuit level is sufficient
Other customer DER adoption forecasts	Description: • DER adoption forecasts take into account customer and system data inputs and assumptions, this information is run through internal modeling with a final product of forecasted amount per year down to the feeder and substation level by year and DER type. SCE Policy: • Provided in Distributed Resources Plan, Chapter 2; Also provided in Worksheets	• Discuss if other DER adoption forecasts including in SCE's DRP meets third parties' needs
Projected 10-year investment needs	Description: • SCE's 3-year projected investment needs are provided in its General Rate Case application • Planning methodology description and overview	• Discuss if SCE's three-year GRC investment forecasts meets third parties' needs

	• Program / project description, justification, and cash flow SCE Policy: • Provide 3-year projected investment need through existing GRC applications (A.13-11-003, SCE-03, Volume 03)	
Customer DG adoption forecasts	Description: • The amount of distributed generation projected to be installed and generating added and cumulative at the feeder and substation level • Data used as an input to SCE's biennially IEPR SCE Policy: • Provide on SCE's DRRP Web Portal	• Discuss whether posting of DG adoption forecasts on DRRP web portal meets third parties' needs • Determine frequency of data posting
EV and charging station populations	Description: • Number and location of charging stations Data to be Provided: • SCE may provide the location of its own charging stations • SCE does not have the location of charging stations owned by other parties SCE Policy: • Provide on SCE's DRRP Web Portal	• Determine how parties can access or provide other parties' charging stations
Coincident peak	Description: • The load profile of any distribution asset with all load and resources aggregated together at a single point in time or during a specified time period. SCE Policy: • Data may be provided in an aggregated form such that specific customer identities will not be compromised • Aggregation techniques must be further defined at workshops, as well as the definition of Coincident Peak (i.e., Coincident Peak reference point must be established) • Can be provided on SCE's DRRP Web Portal	• Determine coincident peak reference point • Determine frequency of data posting • Discuss potential aggregation methods
Distribution Planning load forecast, based on forecasting scenarios proposed elsewhere in the plan	Description: • The changes to the distribution load forecast based on the different levels of DER penetration defined in the three growth scenarios (Trajectory Case, High Case, and 20% DER Case) prescribed in the Final Guidance. SCE Policy: • Data included in DRP	• Discuss if distribution planning load forecasts included in SCE's DRP meets third parties' needs
Backup generator population	Description: • Customer-owned backup generating facilities that are not interconnected with SCE's system. SCE Policy: • Information that SCE currently has on third-party-owned backup generating facilities, aggregated by zip code or other geographic filter to protect customer confidentiality. • Aggregation/anonymization techniques must be further defined at workshops • Can be provided on SCE's DRRP Web Portal	• Determine whether aggregated/anonymized data would be useful to third parties • Discuss potential aggregation/ anonymization techniques • Determine frequency of data posting
Generation production characteristics for	Description: • Generation characteristics such as dependence on weather in order to generate energy such as wind or	• Determine whether aggregated/anonymized data would be useful to

intermittent resources	solar SCE Policy: • Data SCE authorized to collect under Rule 21 (i.e., data for installations of 1 MW and above) aggregated by zip code or other geographic filter to protect customer confidentiality. • Aggregation/anonymization techniques must be further defined at workshops • Can be provided on SCE's DRRP Web Portal • California Solar Initiative program data, including individual project costs, incentives, size, and other data available on California Solar Statistics website	third parties • Discuss potential aggregation/ anonymization techniques • Determine frequency of data posting
Existing combined heat and power installations	Description: • Customer-owned heat and power installations connected to SCE's system SCE Policy: • Information that SCE currently has on third-party-owned backup generating facilities, aggregated by zip code or other geographic filter to protect customer confidentiality. • Aggregation/anonymization techniques must be further defined at workshops • Depending the type of data, SCE may be limited in the data to be shared by contractual agreements Format: Can be provided on SCE's DRRP Web Portal	• Determine whether aggregated data would be useful to third parties • Discuss potential aggregation/ anonymization techniques • Determine frequency of data posting
Demographics: household income levels for CARE customers	Description: • Income information for customers receiving SCE's CARE discount Data Uses: • The value and use to third parties is unclear SCE Policy: • Household income data already available through census bureau. • Customer-specific income information is confidential. • Household income levels for SCE's CARE customers could be made available in aggregated form (e.g., by zip code or other geographic filter) if value is determined	• Determine what value or use this data would be for third parties • Discuss alternative sources of data for third parties • Discuss potential aggregation/ anonymization techniques
Data from sensor systems, SCADA systems, and Substation Automation Systems	Description: • Amp, MW, MVA, voltage, VAR information, facility status information, at the distribution system level and substation level. Data Uses: • Determine whether investment plan matches needs, and identify areas to target DERs. • Develop planning information for capacity and forecasting SCE Policy: • Providing direct access to SCE's SCADA systems or providing granular-level or real-time SCADA data to third parties poses a security risk to the safety of the electric grid. • Providing granular-level detail may enable third parties to identify specific SCE customers, thus raising privacy	• Determine what value or use this data in raw form would be for third parties • Discuss how data could be provided in a meaningful way on DERiM • Discuss safety, customer privacy, and cyber security issues associated with this data

	concerns. • SCADA data can contain information affected by abnormal conditions that could lead to misinterpretation of actual grid conditions • Certain "operational" information from SCE's SCADA systems, such as real-time information about the status of SCE facilities, may be of minimal use to developers. • Certain amounts of "planning" information derived from SCE's SCADA systems are already being provided in DERiM. • May be able to provide time-delayed data of representative days	
Real and Reactive Power Factor	Description: • Real Power is represented in MW and is recorded and stored in the SCADA systems database. • Reactive Power is represented in MVAR and is recorded and stored in the SCADA system database. • Power Factor is calculated based on the relationship between the Real Power and Reactive Power required for the distribution asset to serve. SCE Policy: • See description related to SCADA data above	• Discuss how data could be provided in a meaningful way on DERiM • Discuss safety, customer privacy, and cyber security issues associated with this data
Impedances and Transformer Thermal and Loading Histories	Description: • The Impedance of a transformer is the combination of the resistance and reactance of the primary and secondary windings. The larger the transformer impedance results in more losses through the transformer. • Thermal loading histories relate to the amount of power that has historically been carried by the transformer. This data is contained in the SCADA database. SCE Policy: • See description related to SCADA data above	• Discuss how data could be provided in a meaningful way on DERiM • Discuss safety, customer privacy, and cyber security issues associated with this data

Appendix H: Studies to Evaluate Improved Reliability Due to Distribution Automation

SCE performed a reliability study on its Train 12kV circuit to evaluate the reliability improvement from the addition of remote-controlled switches. Using current data for the circuit, SCE calculated a theoretical baseline circuit-level SAIFI of 1.236 interruptions per year and a circuit-level SAIDI of 148 minutes per year. Assuming various levels of automation on the circuit, new values of circuit-level SAIFI and circuit-level SAIDI were calculated. Each additional remote-controlled switch yielded an improvement in SAIFI and SAIDI. The addition of 3 remote-controlled, “isolation” switches and the addition of one tie switch to the circuit’s one existing tie switch resulted in a new circuit-level SAIFI of 0.483 interruptions per year and a circuit-level SAIDI of 77 minutes per year.

A second, two-part, example of the effectiveness of automation can be seen in the historical reliability of circuits before and after automation was installed. Most of these automation projects installed only one mid-point switch and/or one tie switch to circuits roughly half of which already had some level of existing automation. A study, performed in 2013, looked at 360 circuits that were automated in 2009. SCE calculated their average Customer Minutes of Interruption (CMI) and circuit-SAIDI over the prior three years, i.e., 2006-2008, and compared that with their average CMI and circuit-SAIDI over the following three years, i.e., 2010-2012. A summary of the results is shown in Table H-1. While not every circuit performed better over this short evaluation period, (at least in the following three years due to the nature of probability), the aggregated performance of all the automated circuits showed a significant improvement in reliability, i.e., a reduction in circuit-level SAIDI of 13.76 minutes (or a 10.5% reduction in total CMI).

Table H-1
Results of Reliability Improvement Study (2006-2012)

Using CMI		Using Ckt. SAIDI	
Total Circuits:=	360	Total Circuits:=	360
# improved:=	200	# improved:=	187
# got worse:=	155	# got worse:=	170
# no change:=	5	# no change:=	3
Represents sustained outages for all 3 years (per/post)			
Total CMI (pre):=	79,790,057	Total SAIDI (pre):=	180.27
Total CMI (post):=	71,362,098	Total SAIDI (post):=	166.51
Cust. Avg. (pre):=	442,606	SAIDI Reduction:=	13.76
Cust. Avg. (post):=	428,577		

CMI Reduction	8,427,960
Reduction Per Circuit	**23,411**

A similar study was performed in 2014 examining the improvement in performance of 321 circuits automated in 2010 by comparing their CMI and SAIDI in 2007-2009 with that in 2011-2013. A summary of the results of that study is shown below in Table H-2. Again, not every circuit performed better in the following three years, the aggregated performance of all the automated circuits showed a reduction in circuit-level SAIDI of 17.39 minutes (or a 6.8% reduction in total CMI). This smaller reduction in CMI achieved by the automation projects of 2010 is assumed to be the result of the prioritization process which schedules earlier those circuits where automation is expected to have the greatest impact.

Table H-2
Results of Reliability Improvement Study (2007-2013)

Using CMI		Using Ckt. SAIDI	
Total Circuits:=	321	Total Circuits:=	321
# improved:=	121	# improved:=	120
# got worse:=	153	# got worse:=	154
# no change:=	47	# no change:=	47
Represents sustained outages for all 3 years (per/post)			
Total CMI (pre):=	67,731,456	Total SAIDI (pre):=	166.75
Total CMI (post):=	63,142,670	Total SAIDI (post):=	149.36
Cust. Avg. (pre):=	406,183	SAIDI Reduction:=	17.39
Cust. Avg. (post):=	422,758		

CMI Reduction	4,588,786
Reduction Per Circuit	**14,295**

Appendix I: Integration Capacity Analysis Worksheets

As part of the DRP, SCE determined the potential hosting capacity for the distribution circuits within SCE's Service Territory. The hosting capacity for each distribution circuit, as explained within the DRP Volume 2 Section B, was based on the extrapolation of hosting capacity from the Integration Capacity Analysis of 30 representative distribution circuits. The Hosting Capacity Worksheets, effective June 26, 2015, show the substation name, distribution circuit name, voltage for the distribution circuit, and the potential hosting capacity at the line segment level. Due to the dynamic nature of the distribution system and changes to the interconnection queue, the values shown within the table may differ from the values shown within the Distributed Energy Resource Interconnection Maps (DERiM) that will be published on July 1, 2015.

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Highland	Abacus	12	0.18	0.18	0.18	0.18	3.11	3.11	2.71	2.29
Greening	Abana	12	2.95	0	0	0	3.46	3.46	3.46	3.46
Bliss	Abbey	12	0	0	0	0	0	0	0	0
Ellis	Abbot	12	0	0	0	0	3.36	3.36	3.36	3.29
Bovine	Aberdeen	12	1.28	1.28	1.28	1.28	3.42	3.42	3.42	3.42
Cortez	Abigail	12	1.46	1.46	1.46	1.46	3.36	3.36	3.36	3.36
Cudahy	Able	4.16	0.11	0	0	0	0.78	0	0	0
Neptune	Abri	12	3.02	3.02	3.02	3.02	3.48	3.48	3.48	3.48
Milliken	Absolut	12	0.88	0.88	0.88	0.88	2.79	2.79	2.79	2.78
Newbury	Academy	16	3.97	3.97	3.97	3.97	5.37	4.47	3.95	3.67
Mayberry	Acadian	12	2.74	2.74	2.74	2.74	3.18	3.18	3.18	3.08
Pixley	Acala	12	0	0	0	0	0	0	0	0
Brea	Acapulco	12	0	0	0	0	0	0	0	0
Moreno	Accent	12	0.45	0.45	0.45	0.45	3.07	3.07	2.3	1.96
Timberwine	Access	12	0	0	0	0	0	0	0	0
Goleta	Ace	16	8.28	8.28	5.95	3.97	7.02	5.75	5.19	4.82
Newmark	Ackley	4.16	0.18	0	0	0	0.65	0	0	0
Sullivan	Acme	12	3.02	3.02	3.02	3.02	3.39	3.39	3.39	3.39
Arcadia	Acorn	4.16	0.44	0.44	0.44	0.44	1.11	0.68	0.53	0.45
Randall	Acosta	12	1.57	1.57	1.57	1.57	0	0	0	0
Morro	Acres	12	2.93	2.93	2.93	2.93	2.99	2.99	2.39	2
Anaverde	Acrobat	12	0.48	0.48	0.48	0.48	1.28	1.28	1.1	0.93
Bullis	Ada	4.16	0.11	0.11	0.11	0.11	1.25	1.16	0.65	0.55
Sunnyside	Adair	4.16	0	0	0	0	1	0.86	0.54	0.45
Yukon	Adak	16	7.93	7.93	3.97	3.97	7.19	7.19	6.57	6.03
Victoria	Addis	16	1.39	1.39	1.39	1.39	7.56	6.29	5.66	5.26
Victor	Adelanto	12	1.04	1.04	1.04	1.04	3.17	3.17	2.51	2.11
Chase	Adell	12	1.88	1.88	1.88	1.88	3.46	3.46	3.46	3.46
Pico	Admiral	12	1.59	1.59	1.59	1.59	2.65	2.65	2.65	2.31
Newmark	Adobe	16	9.29	3.97	3.97	3.97	7.95	6.76	6.03	5.58
Camarillo	Adolfo	16	1.77	1.77	1.77	1.77	8.24	7.04	6.22	5.78
Larder	Adriatic	4.16	0	0	0	0	0.59	0	0	0
Cherry	Afton	12	3.02	0	0	0	3.49	0	0	0
Wimbledon	Agassi	12	0.36	0.36	0.36	0.36	3.35	3.35	3.34	2.79
Morro	Agate	12	0	0	0	0	2.84	2.66	2.13	1.76
Tamarisk	Agave	12	0	0	0	0	0	0	0	0
Gisler	Agena	12	0	0	0	0	3.32	3.32	3.32	3.32
Bullis	Agnes	4.16	0.85	0	0	0	0.64	0	0	0
Laguna Bell	Agra	16	2.01	2.01	2.01	2.01	8.51	7.2	6.44	5.98
Hemet	Aguanga	12	3.69	3.69	0	0	3.42	3.42	3.42	3.42
Aha P.T.	Aha	12	0.85	0.85	0.85	0.85	3.49	3.49	3.49	3.49
Pico	Ahoy	12	0	0	0	0	3.49	3.49	3.46	2.92
Cajalco	Aidan	12	2.31	2.31	2.31	2.31	2.74	2.67	2.18	1.79
Marine	Aircraft	16	3.97	0	0	0	9.62	0	0	0
Lancaster	Airport	12	3.02	3.02	3.02	3.02	3.17	3.17	3.17	3.17
Borrego	Ajard	12	3.97	3.97	0	0	3.4	3.4	3.4	3.4
Moulton	Akita	12	0	0	0	0	3.2	3.2	3.2	2.99
Trask	Akron	12	0	0	0	0	3.29	3.29	3.29	3.29
Redlands	Alabama	12	1.48	1.48	1.48	1.48	3.44	3.44	3.44	3.42
Modoc	Alamar	4.16	1.08	1.08	1.01	1.01	1.19	0.81	0.67	0.54
Imperial	Alameda	12	3.01	3.01	3.01	3.01	3.48	3.48	3.48	3.48
Seabright	Alamo	12	0	0	0	0	3.49	3.49	3.49	3.49
Live Oak	Alamosa	12	0	0	0	0	3.36	3.36	3.36	3.28
Yukon	Alaska	16	1.11	1.11	1.11	1.11	7.61	6.06	5.47	5.08
El Nido	Albacore	16	0.34	0.34	0.34	0.34	7.71	6.49	5.8	5.39
Randolph	Albany	16	3.97	3.97	3.97	3.97	8.57	7.17	6.48	5.99
Santa Monica	Albatross	16	3.16	3.16	3.16	3.16	7.9	6.64	6	5.56
Brewster	Alberta	4.16	0.57	0.57	0	0	1.24	1.07	0.62	0.52
Passons	Alburtis	12	0	0	0	0	3.45	3.45	3.45	3.45
Albury P.T.	Albury	4.16	0.49	0	0	0	1.29	0	0	0
Moraga	Alcalde	12	4.2	3.02	3.02	3	2.88	2.88	2.88	2.88
Randolph	Alcoa	16	3.13	3.13	3.13	3.13	8.18	6.82	6.25	5.7
Beverly	Alden	4.16	0	0	0	0	0.58	0	0	0
Palm Springs	Alejo	4.16	0.5	0	0	0	0.54	0	0	0
Arro	Alexander	4.16	0	0	0	0	0.92	0	0	0
Redman	Alfalfa	12	3.02	3.02	3.02	3.02	0	0	0	0
San Miguel	Alfredo	16	2.89	2.89	2.89	2.89	9.89	7.23	6.53	6.05
Peyton	Alicia	12	1.9	1.9	1.9	1.9	3.16	3.16	3.16	3.07
Culver	Alla	16	8.23	8.23	3.97	3.97	6.21	5.17	4.68	4.32
Liberty	Allegiance	12	0	0	0	0	0	0	0	0
Carodean	Allegra	12	1.99	1.99	1.99	1.99	0	0	0	0
Cabrillo	Allergan	12	0.39	0	0	0	3.49	0	0	0
Cortez	Allison	12	2.39	0	0	0	3.48	0	0	0
Camden	Alloy	12	2.19	2.19	2.19	2.19	3.48	3.48	3.48	3.48
Lakewood	Allred	4.16	0	0	0	0	0.86	0.63	0.45	0.38

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Homart	Allstate	12	0.98	0.98	0.98	0.98	3.36	3.36	3.36	3.36
Allview P.T.	Allview	2.4	0.08	0	0	0	1.22	0	0	0
Woodruff	Alma	4.16	0	0	0	0	1.21	0.72	0.55	0.46
Alhambra	Almansor	16	0	0	0	0	8.49	6.58	5.94	5.52
Chestnut	Almond	12	1.49	1.49	1.49	1.49	1.43	1.43	1.43	1.35
Woodruff	Alondra	4.16	0	0	0	0	1.21	0.77	0.59	0.5
Eric	Alora	12	0	0	0	0	3.44	3.44	3.44	3.44
Hoyt	Alpaca	4.16	0	0	0	0	1.25	0.81	0.64	0.54
Telegraph	Alpha	12	0.2	0.2	0.2	0.2	3.43	3.43	3.43	3.43
Alpine P.T.	Alpine	2.4	0.36	0	0	0	1.29	0	0	0
Mayflower	Alster	4.16	0	0	0	0	1.02	0.55	0.55	0.46
Archline	Alstot	12	3.24	3	3	3	3.28	3.28	3.28	3.28
Monrovia	Alta	4.16	0	0	0	0	1.22	0.8	0.64	0.54
Soquel	Alterra	12	0.78	0.78	0.78	0.78	2.92	2.92	2.92	2.83
Michillinda	Altura	4.16	0	0	0	0	1.21	0.76	0.59	0.5
Camden	Aluminum	12	0	0	0	0	2.76	2.76	2.76	2.74
Gonzales	Alvarado	16	2.44	2.44	2.44	2.44	7.7	6.37	5.75	5.32
Farrell	Alvera	12	0.01	0.01	0.01	0.01	2.71	2.71	2.71	2.32
Farrell	Amado	12	1.55	1.55	1.55	1.55	3.02	3.02	3.02	2.73
Gonzales	Amanda	16	1.57	1.57	1.57	1.57	7.94	6.61	5.99	5.55
Merced	Amar	12	0	0	0	0	0	0	0	0
Rio Hondo	Amazon	12	0.69	0.69	0.69	0.69	1.36	1.36	1.36	1.36
Tamarisk	Amber	12	0	0	0	0	0	0	0	0
Oak Park	Ambercrest	16	1.24	1.24	1.24	1.24	5.8	4.97	4.43	4.08
Marymount	Ambersky	16	4.96	3.94	3.94	3.94	10.16	6.2	5.54	5.13
Bradbury	Ambrus	16	2.47	2.47	2.47	2.47	6.93	5.78	5.23	4.85
Diamond Bar	Ambushers	12	1.07	1.07	1.07	1.07	3.34	3.34	3.34	3.34
Riverway	American	12	0	0	0	0	0	0	0	0
Moneta	Amestoy	4.16	0.69	0.69	0.69	0.69	1.21	0.49	0.49	0.41
Archline	Amethyst	12	1.65	1.65	1.65	1.65	2.76	2.76	2.47	2.08
Friendly Hills	Amigo	4.16	0	0	0	0	0.96	0	0	0
Bunker	Ammo	12	0	0	0	0	3.29	3.29	3.29	3.29
Somerset	Amos	4.16	0	0	0	0	0.67	0	0	0
Railroad	Amtrak	12	3.02	0	0	0	3.49	0	0	0
Covina	Amy	4.16	0	0	0	0	1.13	0.66	0.66	0.46
Santa Barbara	Anacapa	4.16	1.01	0	0	0	0.76	0	0	0
North Oaks	Anaconda	16	3.97	3.97	3.97	3.97	7.24	7.24	6.45	5.99
Edinger	Anahurst	4.16	0	0	0	0	0.95	0.59	0.47	0.39
Shuttle	Anakin	12	0.4	0.4	0.4	0.4	2.53	2.53	2.25	1.89
Modoc	Anapamu	4.16	0.76	0	0	0	0.61	0	0	0
San Antonio	Anawalt	12	0.66	0.66	0.66	0.66	3.38	3.38	3.38	3.25
Neptune	Anchor	4.16	1.35	1.35	1.15	1.01	1.16	0.81	0.48	0.41
Yukon	Anchorage	16	4.96	0	0	0	8.04	0	0	0
Glen Avon	Anderson	12	0	0	0	0	3.03	3.03	2.7	2.28
Mira Loma	Andes	12	0.55	0.55	0.55	0.55	0.88	0.88	0.88	0.74
Cucamonga	Andretti	12	1.08	1.08	1.08	1.08	3.49	3.49	3.49	3.39
Padua	Andria	12	0.33	0.33	0.33	0.33	3.17	3.17	3.17	3.17
Naomi	Andrus	4.16	0.62	0	0	0	0.71	0	0	0
San Jacinto	Angela	4.8	0	0	0	0	1.28	0	0	0
Gould	Angeles	16	3.97	3.97	3.97	3.97	8.45	6.77	6.08	5.63
Victoria	Angelina	16	3.02	3.02	3.02	3.02	8.75	7.34	6.56	6.06
Fillmore	Angus	16	2.51	2.51	2.51	2.51	6.15	5.15	4.62	4.3
Merced	Ann	12	1.09	1.09	1.09	1.09	3.3	3.3	3.3	3.3
Santa Rosa	Annenberg	12	0	0	0	0	0	0	0	0
Marion	Annette	12	3.02	3.02	3.02	3	3.23	3.23	3.23	3.23
Lafayette	Annika	12	2.35	2.35	2.35	2.35	3.46	3.46	3.09	2.62
Borrego	Ante	12	0	0	0	0	3.24	3.24	3.24	3.23
Cabrillo	Anteater	12	0.63	0	0	0	3.49	0	0	0
Stoddard	Antil	4.16	0	0	0	0	1.29	0.92	0.55	0.47
Timoteo	Antique	12	2.26	2.26	2.26	2.26	3.47	3.47	3.47	3.46
Nogales	Antler	12	2.39	2.39	2.39	2.39	3.42	3.42	3.31	2.8
Moorpark	Anton	16	8.64	3.97	3.97	3.97	6.29	5.25	4.76	4.39
Sullivan	Antone	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.32
Athens	Antwerp	4.16	1.01	0	0	0	0.62	0	0	0
Lennox	Anza	4.16	0.97	0.97	0.97	0.97	1.29	0.83	0.6	0.51
Athens	Anzac	4.16	0.5	0	0	0	0.64	0	0	0
Corona	Anzar	33	8.38	8.38	8.38	8.38	27	27	27	27
Shawnee	Apache	12	3.02	0	0	0	3.49	0	0	0
Santa Rosa	Apartment	12	0	0	0	0	0	0	0	0
Laguna Bell	Apex	16	8.66	3.97	3.97	3.97	8.98	7.25	6.55	6.08
Auld	Appalousa	12	0	0	0	0	2.08	1.62	1.31	1.08
Naples	Appian	4.16	0	0	0	0	1.12	0.78	0.6	0.51
Citrus	Apple	12	0	0	0	0	3.24	3.24	3.24	2.86
Royal	Appleton	16	0	0	0	0	6.1	5.01	4.47	4.16
Fernwood	Apricot	16	2.41	2.41	2.41	2.41	7.99	6.71	6.02	5.59
Estrella	Aquarius	12	0	0	0	0	3.49	3.49	3.49	3.49
Modena	Arabia	12	0	0	0	0	2.85	2.85	2.85	2.43
Gavilan (115)	Arapaho	12	6.08	6.08	4.54	3.02	3.48	3.48	3.48	3.48
Mesa	Arboles	16	1.28	1.28	1.28	1.28	7.39	6.22	5.6	5.2
Arcadia	Arboretum	16	5.1	5.1	5.1	3.97	7.3	6.12	5.53	5.13

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Inglewood	Arborvitae	4.16	0	0	0	0	1.28	0.87	0.69	0.57
Auld	Archie	33	0	0	0	0	21.45	21.45	13.62	10.61
Bluff Cove	Arcturus	4.16	0.05	0.05	0.05	0.05	0.66	0.43	0.34	0.28
Amador	Arden	4.16	0.15	0.15	0.15	0.15	0.94	0.59	0.47	0.39
Woodruff	Ardis	4.16	0.18	0.18	0.18	0.18	1.23	0.65	0.65	0.54
Calden	Ardmore	16	3.97	3.97	3.97	3.97	8.29	6.93	6.28	5.82
Palm Springs	Arenas	4.16	0.78	0	0	0	0.68	0	0	0
Telegraph	Argo	12	2.55	2.55	2.55	2.55	3.39	3.39	3.39	3.39
Triton	Argonaut	12	2.24	2.24	2.24	2.24	2.86	2.86	2.86	2.86
Broadway	Argonne	12	2.47	2.47	2.47	2.47	3.48	3.48	3.48	3.48
Tenaja Test	Ariel	12	0	0	0	0	2.69	2.69	2.69	2.69
Estrella	Aries	12	2.71	2.71	2.71	2.71	3.46	3.46	3.46	3.46
Sepulveda	Arizona	4.16	0.71	0.71	0.71	0.71	0.8	0.65	0.41	0.34
Solemint	Arlene	16	3.82	3.82	3.82	3.82	7.17	6.02	5.51	5.05
Pedley	Arlington	12	0	0	0	0	3.3	3.3	3.13	2.63
Timoteo	Arliss	12	0	0	0	0	3.27	3.27	3.27	3.09
Pauba	Armada	12	0.74	0.74	0.74	0.74	2.55	2.45	1.93	1.61
Armijo P.T.	Armijo	12	0	0	0	0	0	0	0	0
Grangeville	Armona	4.16	0	0	0	0	0	0	0	0
Montecito	Armour	4.16	0.46	0.46	0.46	0.46	0.95	0.47	0.37	0.31
Narod	Armstrong	12	0	0	0	0	3.49	3.49	3.49	3.49
Colonia	Arneill	16	3.97	3.97	3.97	3.97	7.01	6.29	5.31	4.93
Imperial	Arnett	12	6.49	6.49	3	3	3.43	3.43	3.43	3.43
Santa Rosa	Arnez	12	0	0	0	0	0	0	0	0
MacArthur	Arnold	12	1.16	1.16	1.16	1.16	3.01	2.98	2.38	2.01
Arrington P.T.	Arrington	4.16	0	0	0	0	0.46	0	0	0
Limestone	Arsenic	12	1.83	1.83	1.83	1.83	3.08	3.08	2.84	2.41
Idyllwild	Art	2.4	0.67	0	0	0	0.91	0	0	0
La Fresa	Artisano	16	0	0	0	0	10.67	6.77	5.91	5.47
Morro	Artist	12	2.58	2.58	2.58	2.58	3.23	3.23	3.23	3.04
Bryan	Aruba	12	2.43	0	0	0	3.19	3.19	3.19	3.19
Victoria	Arvana	16	3.94	3.94	3.94	3.94	7.32	6.17	5.55	5.15
Fullerton	Ash	4.16	0	0	0	0	0.76	0	0	0
Anaverde	Ashberry	12	2.43	2.43	2.43	2.43	1.65	1.65	1.41	1.17
Archline	Ashford	12	2.94	2.94	2.94	2.94	3.35	3.35	3.08	2.61
Pearl	Ashland	4.16	0.53	0.53	0.53	0.53	1.02	0.73	0.53	0.45
Ashley P.T.	Ashley	4.16	1.01	0	0	0	1.05	0	0	0
Mayflower	Ashmont	4.16	0	0	0	0	0.77	0	0	0
Torrance	Aspen	16	0.54	0.54	0.54	0.54	7.94	6.42	5.79	5.37
Oasis	Assembly	12	0.36	0.36	0.36	0.36	2.93	2.93	2.71	2.27
Alhambra	Asteroid	16	0	0	0	0	7.59	6.42	5.72	5.32
Victor	Astor	12	0.53	0.53	0.53	0.53	2.68	2.68	2.5	2.12
Corona	Astoria	12	0.46	0.46	0.46	0.46	2.15	2.15	1.95	1.58
Estrella	Astrology	12	3	0	0	0	3.49	0	0	0
Viejo	Atento	12	1.33	1.33	1.33	1.33	2.65	1.83	1.43	1.21
Tamarisk	Athel	12	0	0	0	0	0	0	0	0
Proctor	Athena	12	3.46	3.02	3.02	3.02	3.27	3.27	3.27	3.27
Hathaway	Atherton	12	0	0	0	0	3.47	3.47	3.47	3.47
Las Lomas	Atlanta	12	0	0	0	0	3.33	3.33	3.33	3.33
Bullis	Atlantic	16	1.66	1.66	1.66	1.66	7.03	5.87	5.31	4.93
Francis	Atlas	12	0	0	0	0	3.36	3.36	3.36	3.11
Wakefield	Atmore	16	1.85	1.85	1.85	1.85	7.53	6.28	5.68	5.26
Crown	Atrium	12	0	0	0	0	3.47	3.47	3.47	3.47
Pico	Attica	12	3.02	0	0	0	3.49	0	0	0
Culver	Auburn	16	6.99	3.97	3.94	3.94	7.88	6.51	5.91	5.46
O'neill	Audubon	12	0	0	0	0	3.35	3.35	3.35	3.16
Alder	Augusta	12	0.28	0.28	0.28	0.28	2.61	2.61	2.3	1.78
Tulare	Aurora	12	0	0	0	0	0	0	0	0
Vera	Austin	12	1.57	1.57	1.57	1.57	3.47	3.47	3.47	3.47
Autobody	Autobody	4.16	0	0	0	0	1.29	0	0	0
Farrell	Autry	12	0.55	0	0	0	2.33	2.28	1.86	1.53
Skiland	Autumn	12	0	0	0	0	0	0	0	0
Yorba Linda	Avalanche	12	0	0	0	0	2.58	2.58	2.09	1.73
Shandin	Avanti	12	1.63	1.63	1.63	1.63	2.74	2.7	2.01	1.7
Cabrillo	Avco	12	0.24	0.24	0.24	0.24	3.43	3.43	3.43	3.43
Stetson	Avenger	12	3.83	3.02	3.02	3.02	3.03	2.9	2.24	1.89
San Dimas	Avenida	12	0	0	0	0	3.14	3.11	2.45	2.07
Aventura P.T.	Aventura	12	10	3.02	3.02	3.02	3.1	3.1	3.03	2.57
Narod	Avery	12	0	0	0	0	3.11	3.11	2.71	2.28
Stetson	Aviator	12	0.17	0.17	0.17	0.17	0	0	0	0
Downey	Avon	4.16	0	0	0	0	1.19	0.53	0.53	0.45
La Mirada	Axel	12	3.02	0	0	0	3.43	0	0	0
Ayersman P.T.	Ayersman	2.4	0	0	0	0	1.16	0	0	0
Rolling Hills	Azalia	4.16	0.43	0.43	0.43	0.43	1.19	0.49	0.49	0.41
Puente	Azores	12	0	0	0	0	3.4	3.4	3.3	2.8
Indian Wells	Aztec	12	0	0	0	0	0	0	0	0
Topaz	Azure	4.16	0.27	0	0	0	0.66	0	0	0
Eric	Baber	12	0.35	0.35	0.35	0.35	3.46	3.46	3.46	3.46
Tenaja Test	Babylon	12	2.54	2.54	2.54	2.54	3.08	3.08	3.08	2.65
Milliken	Bacardi	12	0	0	0	0	0	0	0	0

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Neptune	Bach	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Walteria	Bachelor	16	3.97	3.97	3.97	3.97	6.33	5.26	4.8	4.39
Firehouse	Backdraft	12	0.54	0.54	0.54	0.54	0.02	0.02	0.02	0.01
Imperial	Bacon	4.16	0.09	0.09	0.09	0.09	1.19	0.63	0.63	0.52
La Palma	Bacway	12	3.02	3.02	3.02	3.02	3.16	3.16	3.16	3.16
Shandin	Badger	12	2.81	2.81	2.81	2.81	3.35	3.35	3.35	3.19
Badwater P.T.	Badwater	12	3.02	3.02	3.02	3.02	3.49	3.12	3.12	3.12
Bryan	Bahama	12	2.96	2.96	2.96	2.96	2.94	2.94	2.94	2.59
Navy Mole	Bainbridge	12	3.78	0	0	0	3.49	0	0	0
Brea	Baja	12	2.96	2.96	2.96	2.96	3.25	3.25	3.25	2.92
Crown	Balboa	12	2.16	2.16	2.16	2.16	3.28	3.28	3.28	3.28
Fillmore	Balcom	16	2.86	2.86	2.86	2.86	5.57	4.65	4.2	3.9
Eaton	Baldwin	16	0	0	0	0	6.92	5.1	4.63	4.28
Upland	Baldy	4.16	0.19	0	0	0	0.61	0	0	0
Laurel	Ball	12	0	0	0	0	0	0	0	0
Narrows	Ballard	12	1.15	1.15	1.15	1.15	3.03	3.03	3.03	2.61
Nola	Ballast	16	1.44	1.44	1.44	1.44	8.3	6.91	6.23	5.79
Sepulveda	Ballona	16	4.53	3.97	3.97	3.97	10.08	9.04	7.21	6.69
Moraga	Balloon	12	0	0	0	0	2.53	2.53	2.08	1.76
Narod	Ballzak	12	0	0	0	0	3.35	3.35	3.22	2.69
Hesperia	Balsam	12	2.93	2.93	2.93	2.93	3.43	3.43	3.43	3.43
Declez	Bamboo	12	0	0	0	0	1.16	1.16	1.16	0.98
Citrus	Banana	12	0	0	0	0	2.63	2.63	2.63	2.58
Jersey	Bancroft	16	0	0	0	0	9.15	7.33	6.92	6.08
Chino	Bandag	12	2	2	2	2	3.49	3.49	3.49	3.49
Concho	Bandana	12	0	0	0	0	0	0	0	0
Francis	Bandera	12	0.91	0.91	0.91	0.91	3.39	3.39	3.39	3.39
Diamond Bar	Bandit	12	0.81	0.81	0.81	0.81	2.9	2.9	2.24	1.89
Niguel	Banjo	12	1.11	1.11	1.11	1.11	3.06	3.06	3.06	2.69
Sunnyside	Banner	12	3.33	3.02	3.02	3.02	3.47	3.47	3.47	3.47
Havasu	Banshee	16	1.33	1.33	1.33	1.33	13.2	5.44	5.44	5.44
Archline	Banyan	12	0.56	0.56	0.56	0.56	3.33	3.33	3.33	3.33
Bryan	Barbados	12	1.03	1.03	1.03	1.03	3.34	3.34	3.32	2.81
Lark Ellen	Barbara	12	1.03	1.03	1.03	1.03	3.47	3.47	3.47	3.47
Maxwell	Barbee	12	5.4	3.02	3.02	3	3.47	3.47	3.47	3.47
Cortez	Barbossa	12	0	0	0	0	2.82	2.82	2.82	2.82
Las Lomas	Barcelona	12	0.53	0.53	0.53	0.53	3.19	3.19	3.19	2.88
Bard P.T.	Bard	4.16	0.12	0.12	0.12	0.12	1.08	0.71	0.56	0.47
Cabrillo	Bardeen	12	0	0	0	0	3.42	3.42	3.42	3.09
Merced	Bardo	12	1.78	1.78	1.78	1.78	3.44	3.44	3.44	3.44
Bridge	Barge	4.16	0.31	0	0	0	0.68	0	0	0
Padua	Barilla	12	0.93	0.93	0.93	0.93	2.89	2.89	2.53	2.13
La Canada	BarleyFlats	16	4.96	4.96	4.96	4.53	7.81	6.49	5.87	5.44
Fernwood	Barlow	16	2.62	0	0	0	7.18	0	0	0
Tahiti	Barnacle	16	8.05	3.94	3.94	3.94	9.94	7.69	7.1	6.42
Gale	Baroid	33	0	0	0	0	0	0	0	0
Upland	Barr	4.16	0	0	0	0	1.23	0	0	0
El Nido	Barracuda	16	0.33	0.33	0.33	0.33	7.65	6.43	5.72	5.31
Covina	Barranca	4.16	0.19	0	0	0	0.64	0	0	0
Maxwell	Barratt	12	0.04	0.04	0.04	0.04	3.41	3.41	3.41	3.28
Fillmore	Barrington	16	3.97	3.97	3.97	3.97	5.77	4.82	4.36	4.04
Garvey	Bartlett	4.16	0.86	0.86	0.86	0.86	1.25	1.08	0.63	0.53
Tippecanoe	Barton	4.16	0.8	0	0	0	1.29	0.62	0.62	0.53
San Antonio	Baseline	12	0	0	0	0	3.02	3.02	3.02	2.68
Moulton	Basenji	12	0	0	0	0	3.35	3.35	3.35	3.35
Moreno	Basil	12	0.59	0.59	0.59	0.59	3.26	3.26	3.26	2.81
Bayside	Bass	12	1.57	1.57	1.57	0	3.49	3.49	3.49	3.49
Niguel	Bassoon	12	0.95	0	0	0	3.49	3.49	3.49	3.49
Bradbury	Bateman	16	1.81	1.81	1.81	1.81	8.17	6.81	6.14	5.7
Santa Barbara	Bath	4.16	1.01	1.01	1.01	1.01	1.21	0.75	0.61	0.5
Eisenhower	Battalion	12	0.66	0.66	0.66	0.66	3.18	3.18	3.11	2.63
Crest	Bauxite	16	1.52	1.52	1.52	1.52	6.76	5.68	5.14	4.76
State Street	Baxter	12	2.84	2.84	2.84	2.84	3.17	3.17	3.17	3.17
Soquel	Bayberry	12	0	0	0	0	2.92	2.92	2.71	2.29
Canyon Lake	Bayliner	12	3.2	3.02	3.02	3.02	2.83	2.83	2.83	2.42
Villa Park	Baylor	12	0	0	0	0	3.17	3.17	3.17	3.17
Amador	Bayse	4.16	0	0	0	0	0.85	0.85	0.67	0.56
Paularino	Bayview	4.16	0.79	0	0	0	0.58	0	0	0
Bunker	Bazooka	12	0.56	0.56	0.56	0.56	1.48	1.29	1.03	0.87
Oceanview	Beach	12	4.81	3.02	3.02	3.02	3.43	3.43	3.43	3.43
Santa Monica	Beachcomber	16	3.97	3.97	3.97	3.97	9.04	7.6	6.83	6.34
Moulton	Beagle	12	5.02	5.02	3.02	3.02	3.47	3.47	3.47	3.47
San Gabriel	Bean	4.16	0.23	0.23	0.23	0.23	1.22	0.55	0.55	0.47
Maywood	Bear	4.16	0.28	0	0	0	0.68	0	0	0
Skylark	BearCreek	12	3.02	0	0	0	3.44	0	0	0
Zanja	BearValley	33	6.6	6.6	6.6	6.6	26.12	15.09	11.08	8.67
Colonia	Beardsley	16	0	0	0	0	4.94	4.06	3.65	3.39
Ganesha	Beasley	12	3.5	3.02	3.02	3.02	3.41	3.41	3.41	3.41
Porterville	Beattie	12	0	0	0	0	0	0	0	0
Wheatland	Beaver	12	0	0	0	0	0	0	0	0

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Newcomb	Becker	12	2.81	2.81	2.81	2.81	2.22	2.22	2.03	1.71
Stetson	Beechcraft	12	7.13	7.13	6.05	6.05	3.4	3.4	3.32	3.32
Kramer	Beechers	2.4	0	0	0	0	0	0	0	0
Chestnut	Beechnut	12	2.61	2.61	2.61	2.61	0	0	0	0
Archline	Beechwood	12	1.09	1.09	1.09	1.09	3.04	3.04	3.04	2.98
Auld	Beeler	12	0	0	0	0	1.74	1.74	1.5	1.26
Victor	Beeline	12	2.16	2.16	2.16	2.16	3	2.56	2.04	1.72
Chestnut	Beernut	12	0	0	0	0	3.37	3.37	3.37	3.3
Bassett	Beezwax	12	1.46	1.46	1.46	1.46	3.39	3.39	3.39	3.33
Fairview	Begonia	12	2.03	2.03	2.03	2.03	3.36	3.36	3.36	3.36
Orange	Beige	12	1.11	1.11	1.11	1.11	3.44	3.44	3.44	3.44
Las Lomas	Beijing	12	0	0	0	0	0	0	0	0
Palm Springs	Belardo	4.16	0	0	0	0	0.91	0.55	0.43	0.36
Amalia	Beldon	4.16	0.27	0	0	0	0.68	0	0	0
Trask	Belfast	12	1.66	1.66	1.66	1.66	3.36	3.36	3.36	3.31
Allen	Bellford	4.16	0.03	0.03	0.03	0.03	1.17	0.73	0.58	0.49
Newbury	Belpac	16	0.54	0.54	0.54	0.54	6.37	5.34	4.84	4.48
Etiwanda	Belushi	12	1.33	1.33	1.33	1.33	1.06	0.95	0.77	0.64
Colton	Bemis	12	0	0	0	0	3.49	0	0	0
Bain	BenNevis	12	0	0	0	0	1.93	1.93	1.93	1.77
Covina	Benbow	4.16	0	0	0	0	0.75	0	0	0
Yucaipa	Bench	12	1.82	1.82	1.82	1.82	1.96	1.75	1.4	1.17
Dalton	Bender	12	1.04	1.04	1.04	1.04	3.37	3.37	3.37	2.97
Beverly	Benedict	4.16	0.05	0.05	0.05	0.05	0.77	0.51	0.4	0.33
Walteria	Benhill	16	2.63	2.63	2.63	2.63	8.77	7.4	6.76	6.16
Hathaway	Bennett	12	0.11	0.11	0.11	0.11	3.4	3.4	3.23	2.73
Etiwanda	Benny	12	0	0	0	0	0.99	0.99	0.99	0.99
Chino	Benson	12	2.47	2.47	2.47	2.47	3.27	3.27	3.17	2.68
Ivar	Bentel	4.16	0.3	0.3	0.3	0.3	1.24	0.86	0.69	0.58
Alessandro	Benton	12	0	0	0	0	3.33	3.33	3.08	2.47
Oldfield	Bentree	4.16	0	0	0	0	1.11	0.79	0.6	0.51
Oasis	Beone	12	3.02	3.02	3.02	3.02	3.4	3.4	2.92	2.46
Arro	Berkley	4.16	0	0	0	0	1.28	0.94	0.69	0.59
Arroyo	Berkshire	4.16	0.02	0.02	0.02	0.02	0.77	0.51	0.4	0.33
Fullerton	Berlin	12	0.17	0.17	0.17	0.17	3.17	3.17	3.17	3.08
Saugus	Bermite	16	0.24	0.24	0.24	0.24	7.56	6.01	5.35	4.97
Bryan	Bermuda	12	2.92	2.92	2.92	2.92	3.38	3.38	3.38	3.38
Linden	Bernard	4.16	0.51	0	0	0	0.51	0	0	0
Marion	Bernice	12	0.43	0.43	0.43	0.43	3.48	3.48	3.48	3.48
Flanco	Berry	4.16	0.11	0	0	0	0.71	0	0	0
Cabrillo	Bertea	12	0	0	0	0	3.49	3.49	3.49	3.48
Marion	Bertha	12	1.57	1.57	1.57	1.57	3.36	3.36	3.36	3.36
Redondo	Beryl	4.16	0.64	0	0	0	0.82	0	0	0
Bessemer P.T.	Bessemer	12	0.86	0	0	0	3.49	0	0	0
Telegraph	Beta	12	0.88	0.88	0.88	0.88	3.36	3.36	3.36	3.36
Bartolo	Bexley	4.16	0.11	0	0	0	0.7	0	0	0
Padua	Bianco	12	0	0	0	0	2.88	2.88	2.86	2.41
Goleta	Bidder	16	7.51	5.95	5.95	3.97	7.06	5.78	5.2	4.82
Temple	Bidwell	4.16	0.04	0	0	0	0.8	0	0	0
Live Oak	BigCone	12	1.26	1.26	1.26	1.26	0	0	0	0
Forest Home	BigFalls	2.4	0.42	0	0	0	1.01	0	0	0
Little Rock	BigPines	12	1.71	1.71	1.71	1.71	0	0	0	0
Declez	BigRigg	12	0	0	0	0	3.41	3.41	3.41	2.9
Chatsworth	BigRock	16	0.62	0.62	0.62	0.62	6.81	5.86	5.05	4.68
Lucas	Bigelow	12	3.02	3.02	3.02	3.02	3.42	3.42	3.06	2.6
Bigfoot P.T.	Bigfoot	4.16	0	0	0	0	0	0	0	0
Biggs P.T.	Biggs	4.16	0	0	0	0	1.19	0	0	0
Santa Rosa	Bighorn	12	0	0	0	0	0	0	0	0
Blythe City	Bigler	4.8	1.01	0	0	0	0.73	0	0	0
Layfair	Bill	12	0	0	0	0	3.13	0	0	0
Fairview	Billings	12	2.85	0	0	0	3.36	0	0	0
Fogarty	Billy	12	4.69	0	0	0	3.46	0	0	0
Line Creek	BillyCreek	4.16	0	0	0	0	0	0	0	0
Rosemead	Bilton	16	2.15	2.15	2.15	2.15	7.23	6.01	5.39	5.01
Maraschino	Bing	12	2.05	2.05	2.05	2.05	3.3	3.3	2.93	2.47
Johanna	Bingo	12	0	0	0	0	3.49	3.49	3.49	3.49
Walnut	Binney	12	1.49	1.49	1.49	1.49	3.36	3.36	3.36	3.21
Telegraph	Biola	12	0.97	0.97	0.97	0.97	3.36	3.36	3.34	2.83
Stetson	Biplane	12	0	0	0	0	2.24	2.24	2.24	2.24
Tamarisk	Birch	12	0	0	0	0	0	0	0	0
Mt. Tom	Birchim	12	0	0	0	0	0	0	0	0
Oak Park	Birchwood	16	0	0	0	0	6.66	5.56	5	4.63
Bowl	Bird	12	3.97	0	0	0	3.49	3.49	3.49	3.49
Oceanview	Bishop	12	1.24	1.24	1.24	1.24	3.48	3.48	3.48	3.46
Camden	Bismuth	12	1.77	1.77	1.77	1.77	3.43	3.43	3.43	3.43
Lampson	Bison	12	0.23	0.23	0.23	0.23	3.42	3.42	3.42	3.42
Nelson	Bissell	12	0	0	0	0	3.34	3.34	3.34	2.98
Silver Spur	Bit	12	0	0	0	0	0	0	0	0
Soquel	Bittern	12	0.25	0.25	0.25	0.25	3.08	3.08	3.08	3.02
Orange	Black	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49

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Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Lockheed	Blackbird	16	2.94	2.94	2.94	2.94	5.72	4.66	4.19	3.85
El Sobrante	Blackburn	12	0	0	0	0	2.75	2.75	2.75	2.45
Gavilan (115)	Blackfoot	12	0	0	0	0	2.56	2.56	2.27	1.91
Shawnee	Blackhawk	12	0.51	0.51	0.51	0.51	3.25	3.25	3.25	3.15
Glen Avon	Blackhills	12	0.41	0.41	0.41	0.41	2.41	2.41	2.41	2.2
Torrance	Blackjack	16	3.9	3.9	3.9	3.9	9.41	7.43	6.51	6.03
Liberty	Blackstone	12	0	0	0	0	0	0	0	0
Lunada	Blackwater	4.16	0	0	0	0	0.96	0	0	0
Imperial	Blaine	12	3.02	0	0	0	3.49	0	0	0
La Fresa	Blake	16	0	0	0	0	6.31	5.31	4.74	4.4
Columbine	Blanca	12	0	0	0	0	0	0	0	0
Repetto	Blanchard	16	0	0	0	0	7.27	6.1	5.52	5.11
El Porto	Blanche	4.16	2.3	0	0	0	1.18	0	0	0
Center	Blanket	12	4.44	4.44	4.44	3.02	3.49	3.49	3.49	3.49
Firehouse	Blaze	12	2.64	2.64	2.64	2.64	3.49	3.49	3.49	3.49
Stadler	Bleacher	12	0	0	0	0	3	3	3	2.68
Neenach	Bledsoe	12	3.71	3.02	3.02	3.02	3.39	2.28	1.81	1.51
Rush	Bleeker	16	3.97	0	0	0	8.88	0	0	0
Coffee	Blend	12	0.73	0.73	0.73	0.73	2.75	2.75	2.75	2.42
Nola	Blimp	16	0	0	0	0	6.65	5.59	5.05	4.68
Pixley	Blinker	12	0	0	0	0	0	0	0	0
Stadler	Blitz	12	0	0	0	0	2.94	2.94	2.94	2.51
Yorba Linda	Blizzard	12	0	0	0	0	3.07	3.07	3.07	3.07
Walteria	Blocker	16	3.69	3.69	3.69	3.69	7.31	6.13	5.51	5.11
Topaz	Bloodstone	4.16	0	0	0	0	1.27	0.89	0.69	0.58
Victoria	Blossom	16	5.97	5.97	5.97	3.97	8.24	6.93	6.24	5.78
Desert Outpost	BlowSand	12	0	0	0	0	3.34	3.34	3.34	3.34
Orange	Blue	12	1.48	1.48	1.48	1.48	3.42	3.42	3.42	3.42
Perez	BlueCrest	4.16	0	0	0	0	1.28	0	0	0
Blue Cut P.T.	BlueCut	12	0.54	0.54	0.54	0.54	3.19	2.94	2.35	1.97
Blue Ridge P.T.	BlueRidge	2.4	0.16	0.16	0.16	0.16	1.28	0.88	0.49	0.49
Thunderbird	BlueSkies	4.8	0	0	0	0	0	0	0	0
Citrus	Blueberry	12	0.3	0.3	0.3	0.3	3.18	3.18	3.18	3.05
La Mirada	Bluefield	12	3.04	3.04	3.02	3.02	3.24	3.24	3.24	3.24
El Nido	Bluegill	16	3.86	3.86	3.86	3.86	8.45	6.84	6.17	5.73
Jefferson	Bluemoon	12	0	0	0	0	3.18	3.18	3.18	3.18
North Oaks	Boa	16	1.87	1.87	1.87	1.87	5.31	5.31	4.83	4.45
Blythe City	Boat	33	8.38	8.38	8.38	8.38	27	27	22.45	16.71
Bloomington	Bobber	12	0	0	0	0	3.26	3.26	2.83	2.38
Chase	Bobbit	12	0	0	0	0	2.37	2.37	2.37	1.99
Merced	Bobby	12	0	0	0	0	3.06	3.06	3.06	2.79
Wheatland	Bobcat	12	0	0	0	0	0	0	0	0
Skiland	Bobsled	12	0	0	0	0	0	0	0	0
Skylark	Bodkin	12	5.9	4.21	3.02	3.02	3.19	3.19	3.19	3.19
Lennox	Boeing	16	2.94	2.94	2.94	2.94	6.7	5.47	5.01	4.58
Movie	Bogart	16	3.32	3.32	3.32	3.32	8.36	6.97	6.28	5.84
Defrain	Bogey	12	4.54	4.54	4.54	4.54	3.28	3.28	2.72	2.3
Jefferson	Bohemia	12	0.49	0.49	0.49	0.49	2.78	2.78	2.78	2.78
Savage	Boise	12	0.05	0.05	0	0	1.43	1.43	1.19	0.98
Fremont	Boland	4.16	0.43	0.43	0.43	0.43	1.25	0.72	0.53	0.44
Ely	Bolivia	12	4.04	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Corona	Bollero	12	0	0	0	0	2.62	2.62	2.57	2.17
Alder	Bolor	12	0	0	0	0	2.78	2.78	2.77	2.35
Jersey	Bolton	16	7.55	3.97	3.97	3.94	7.35	6.1	5.52	5.12
Eisenhower	Bombardier	12	0	0	0	0	3.08	3.08	3.08	2.7
Bloomington	Bombay	12	5.35	3	3	3	0	0	0	0
Kernville	Bonanza	12	0	0	0	0	0	0	0	0
Watson	Bond	12	0	0	0	0	3.49	3.49	3.49	3.49
Nuevo	Bonge	12	2.74	2.74	2.74	2.74	0	0	0	0
San Dimas	Bonita	12	1.09	1.09	1.09	1.09	2.95	2.95	2.95	2.95
Topanga	Bonnell	4.16	1.01	1.01	1.01	1.01	1.17	0.62	0.46	0.39
Duarte	Bonnie	4.16	0	0	0	0	1.15	0.74	0.56	0.48
Live Oak	Bontanic	12	0	0	0	0	3.28	3.28	3.28	3.2
Narod	Bonview	12	0.91	0.91	0.91	0.91	3.49	3.49	3.49	3.49
Tortilla	Book	33	0	0	0	0	0	0	0	0
Columbine	Boone	12	0	0	0	0	0	0	0	0
Lindsay	Booster	12	0	0	0	0	0	0	0	0
Diamond Bar	Boothill	12	0.84	0.84	0.84	0.84	2.06	2.06	2.06	1.92
Acton	Bootlegger	12	1.81	1.81	1.81	1.81	0.89	0.6	0.48	0.4
Archibald	Borba	12	4.93	4.93	3.02	3.02	3.38	3.38	3.22	2.73
Newbury	Borchard	16	2.03	2.03	2.03	2.03	7.84	6.52	5.87	5.45
O'neill	Borchers	12	0.27	0.27	0.27	0.27	2.36	2.36	2.36	2.36
Pauba	Bordeaux	12	0.92	0.92	0.92	0.92	3.17	3.17	2.82	2.21
Ditmar	Borden	4.16	0.24	0	0	0	0.67	0	0	0
Jefferson	Border	12	0	0	0	0	3.43	3.43	3.43	3.29
Wimbledon	Borg	12	0.07	0.07	0.07	0.07	3.46	3.46	3.46	3.46
Bandini	Boris	16	3.94	3.94	3.94	3.94	9.62	7.79	7.02	6.52
Modena	Borneo	12	0.64	0.64	0.64	0.64	2.8	2.8	2.8	2.41
Sunnyside	Bort	12	1.29	1.29	1.29	1.29	3.48	3.48	3.48	3.48
Cortez	Bosco	12	2.15	2.15	2.15	2.15	3.44	3.44	3.44	3.44

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Graham	Boston	4.16	0.78	0	0	0	0.61	0	0	0
Highland	Boulder	12	0	0	0	0	2.78	2.78	2.45	2.07
Linden	Boulevard	4.16	0.32	0	0	0	0.92	0	0	0
Solemint	Bouquet	16	5.52	3.97	3.97	3.97	5.54	4.37	4.18	3.66
Pico	Bow	12	1.34	1.34	1.34	1.34	3.29	3.29	3.29	3.29
Strathmore	Bowen	12	0	0	0	0	0	0	0	0
Pioneer	Bowie	12	2.39	2.39	2.39	2.39	3.48	3.48	3.48	3.48
Downs	Bowman	12	0	0	0	0	0	0	0	0
Calectric	BoxSpring	33	16.17	0	0	0	27	0	0	0
Goldtown	Boxcar	12	2.37	2.37	2.37	2.37	1.91	1.66	1.32	1.1
Center	Boxer	12	1.16	1.16	1.16	1.16	3.47	3.47	3.47	3.47
Layfair	Boyalta	12	1.24	1.24	1.24	1.24	3.04	3.04	3.04	3.04
Stadium	Boyd	12	0.69	0.69	0.69	0.69	2.06	2.06	1.94	1.64
Sunnyside	Boyer	12	3.02	0	0	0	3.45	0	0	0
Fruitland	Boyle	4.16	1.01	0	0	0	0.66	0	0	0
Cucamonga	Boynton	12	0.73	0.73	0.73	0.73	2.46	2.46	2.46	2.23
Villa Park	Boysen	12	0.07	0.07	0.07	0.07	3.34	3.34	3.34	3.34
Layfair	Brackett	12	0	0	0	0	3.28	3.28	3.28	2.94
Newcomb	Bradley	12	0.64	0.64	0.64	0.64	3.33	3.33	3.33	3
Del Amo	Bradshaw	12	0	0	0	0	3.49	3.49	3.49	3.49
Allen	Braeburn	4.16	0	0	0	0	0.79	0.44	0.34	0.29
Playa	Braemer	4.16	0.13	0.13	0.13	0.13	0.97	0.61	0.47	0.39
Harvard	Bragdon	12	0	0	0	0	0	0	0	0
Bovine	Brahma	12	1.81	1.81	1.81	1.81	3.31	3.31	3.31	3.31
Lucas	Brakebill	12	0	0	0	0	2.82	2.82	2.82	2.82
Railroad	Brakeman	12	0.57	0.57	0.57	0.57	3.1	3.07	2.43	2.06
Torrance	Bramble	16	3.97	0	0	0	7.43	0	0	0
Santa Susana	Brand	16	0	0	0	0	7.35	6.17	5.51	5.12
Fullerton	Brashears	12	0	0	0	0	3.34	3.34	3.34	3.26
Alhambra	Braun	16	2.88	0	0	0	6.73	0	0	0
Archibald	Bravon	12	0	0	0	0	2.68	2.68	2.26	1.89
Bowl	Brayton	4.16	0.31	0	0	0	0.63	0	0	0
Bryan	Brazil	12	3.64	3.02	3.02	3.02	3.33	3.33	3.33	3.33
Dryden P.T.	Breakwater	12	0	0	0	0	3.49	0	0	0
Merced	Bren	12	2.36	2.36	2.36	2.36	0	0	0	0
Moorpark	Brennan	16	2.36	2.36	2.36	2.36	5.76	4.15	3.73	3.47
Garfield	Brent	4.16	0.45	0	0	0	0.71	0	0	0
Los Cerritos	Brethren	12	0	0	0	0	3.35	3.35	3.35	3.35
Atwood	Breting	12	0.49	0.49	0	0	3.27	3.27	3.27	3.27
Mira Loma	Brewer	12	0	0	0	0	3.49	0	0	0
Bandini	Brickyard	16	3.29	3.29	3.29	3.29	7.8	6.35	5.73	5.32
La Habra	Bride	12	2.01	0	0	0	3.49	0	0	0
Stirrup	Bridle	4.16	0.16	0.16	0.16	0.16	0.65	0.44	0.34	0.29
Neptune	Brine	12	3.02	3.02	3.02	3.02	3.46	3.46	3.46	3.46
Pico	Brink	12	8.88	7.67	7.67	3	3.49	3.49	3.49	3.49
Model P.T.	Brinkley	12	2.11	2.11	2.11	2.11	3.49	3.32	2.68	2.22
Sullivan	Brittan	12	2.41	2.41	2.41	2.41	3.46	3.46	3.46	3.46
Calcity 'A'	BrittleBush	12	0	0	0	0	0	0	0	0
Gould	Broadcast	33	14.06	14.06	14.06	14.06	27	21.37	13.12	10.44
Narrows	Bronco	12	0	0	0	0	3.44	3.44	3.44	3.31
Sharon	Brookhill	4.16	0.19	0	0	0	1.25	0	0	0
Rush	Brookline	16	0.51	0.51	0.51	0.51	6.94	5.85	5.25	4.87
Belvedere	Brooklyn	4.16	0.28	0.28	0.28	0.28	1.27	0.87	0.69	0.58
Amador	Brooks	4.16	0	0	0	0	1.04	0.48	0.48	0.4
Redlands	Brookside	4.16	0.04	0.04	0.04	0.04	0.72	0.47	0.37	0.31
Colonia	Broome	16	0	0	0	0	10.73	5.43	5.43	4.95
Corona	Brotherton	12	0.07	0.07	0.07	0.07	3.3	3.3	3.12	2.6
Brown P.T.	Brown	4.16	0	0	0	0	1.18	0	0	0
Blythe City	BrucePark	4.8	0.2	0	0	0	0.62	0	0	0
Victor	Brucite	12	2.35	2.35	2.35	2.35	2.87	2.87	2.39	2.03
Auld	Brumfield	12	3.48	3.48	3.48	3.48	3.09	3.09	3.09	2.8
Alhambra	Brunner	4.16	0	0	0	0	0.76	0	0	0
Padua	Bruno	12	1.76	1.76	1.76	1.76	2.94	2.94	2.57	2.18
Maxwell	Brutte	12	0	0	0	0	3.41	3.41	3.41	2.98
La Fresa	Bryant	16	3.97	3.97	3.97	3.97	9.88	7.28	6.57	6.09
Amador	Bryce	16	0	0	0	0	7.05	5.79	5.25	4.85
San Dimas	Brydon	12	0.96	0.96	0.96	0.96	3.34	3.34	3.34	3.34
Redlands	BrynMawr	12	1.67	1.67	1.67	1.67	2.43	2.43	1.99	1.67
La Mirada	Buck	12	0.54	0	0	0	0.56	0	0	0
Gonzales	Buckaroo	16	2.42	2.42	2.42	2.42	4.88	4.08	3.68	3.42
Ivyglen	Buckboard	12	2.8	2.8	2.8	2.8	3.35	3.35	3.35	2.96
Fillmore	Buckhorn	16	0	0	0	0	0.71	0.59	0.53	0.5
Royal	Buckner	16	0	0	0	0	5.49	4.62	4.17	3.86
Hesperia	Buckthorn	12	3.52	3.52	3.02	3.02	3.04	3.04	2.83	2.38
Pixley	Budd	12	0	0	0	0	0	0	0	0
Howard	Budlong	4.16	0	0	0	0	1.28	1.03	0.64	0.54
Center	Buffalo	12	3.02	3.02	3.02	3.02	3.17	3.17	3.17	3.17
Chatsworth	Buffer	16	3.98	3.97	3.97	3.97	6.88	4.61	4.18	3.86
Greening	Buford	12	2.96	2.96	2.96	2.96	3.41	3.41	3.41	3.41
Gale	Bug	33	0	0	0	0	0	0	0	0

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Eisenhower	Buldge	12	0.47	0.47	0.47	0.47	2.86	2.86	2.59	2.17
Moulton	Bulldog	12	1.82	1.82	1.82	1.82	3.37	3.37	3.37	3.37
Pomona	Bulletin	4.16	0.55	0.55	0.55	0.55	0.81	0.49	0.38	0.32
Triton	Bullhead	12	2.76	2.76	2.76	2.76	3.35	3.35	3.35	3.35
Sullivan	Bullocks	12	2.81	0	0	0	3.47	0	0	0
Mascot	Bullpup	12	0	0	0	0	0	0	0	0
Skylark	Bundy	12	3.12	3.12	3.02	3.02	3.1	3.1	3.1	3.06
Sepulveda	Bungalow	16	3.97	0	0	0	7.17	0	0	0
Beverly	Bunny	16	3.06	0	0	0	7.1	0	0	0
Ganesha	Burdick	4.16	0.5	0	0	0	1.27	0.81	0.65	0.54
Bicknell	Burger	4.16	0	0	0	0	1.29	1.18	0.66	0.53
Pepper	Burgundy	12	1.69	1.69	1.69	1.69	3.03	3.03	2.99	2.52
Holiday	Burkett	4.16	0	0	0	0	0.53	0	0	0
Yukon	Burleigh	4.16	0.95	0.95	0.95	0.95	0.9	0.64	0.47	0.39
Royal	Burleson	16	0	0	0	0	5.4	4.68	4.13	3.8
Jersey	Burma	16	3.22	3.22	3.22	3.22	8.44	6.94	6.26	5.82
Yucaipa	Burns	12	2.6	2.6	2.6	2.6	2.97	2.97	2.97	2.83
Yucca	BurntMountain	12	2.91	2.91	2.91	2.91	1.66	1.53	1.21	1.03
Lindsay	Burr	12	0	0	0	0	0	0	0	0
Hanford	Burris	12	0	0	0	0	0	0	0	0
Tortilla	Burrito	12	0	0	0	0	0	0	0	0
Ridgecrest	Burroughs	4.8	0	0	0	0	0	0	0	0
Porterville	Burton	12	0	0	0	0	0	0	0	0
Mariposa	Burum	12	0	0	0	0	0	0	0	0
Savage	Burwood	12	0.07	0.07	0.07	0.07	2.52	2.52	2.52	2.21
Rector	Bush	12	0	0	0	0	0	0	0	0
Oceanview	Bushard	12	0.11	0.11	0.11	0.11	3.17	3.17	3.17	3.17
East Barstow	Business	4.16	0	0	0	0	0	0	0	0
Sepulveda	Butane	16	3.97	3.97	3.97	3.97	7.39	6.24	5.58	5.18
Carmenita	Butler	12	3.11	3.11	3.11	3.11	2.44	2.44	2.44	2.44
Rosamond	Butte	12	1.22	1.22	1.22	1.22	2.91	2.91	2.91	2.63
Soquel	Butterfield	12	2.17	2.17	2.17	2.17	2.34	2.34	1.97	1.66
Chestnut	Butternut	12	3.02	0	0	0	2.54	0	0	0
Thousand Oaks	Byer	16	0	0	0	0	6.1	5.09	4.66	4.26
Stoddard	Byron	4.16	2.14	0	0	0	1.22	0	0	0
Delano	CBS	12	0	0	0	0	0	0	0	0
Holiday	Caballeros	4.16	0	0	0	0	0.95	0.77	0.48	0.41
Bain	Cabana	12	1.53	1.53	1.53	1.53	2.46	2.46	2.46	2.46
Pepper	Cabernet	12	3.02	3.02	3.02	3.02	3.42	3.42	3.42	3.32
San Antonio	Cable	12	0.44	0.44	0.44	0.44	2.94	2.94	2.94	2.82
Railroad	Caboose	12	0.61	0.61	0.61	0.61	3.31	3.31	3.31	3.31
Madrid	Cabrillo	4.16	0.78	0.78	0.78	0.78	1.27	0.8	0.63	0.53
Vegas	Cachuma	16	2.19	2.19	2.19	2.19	3.68	3.12	2.78	2.59
Colton	Cactus	12	7.66	7.66	7.66	3.02	2.41	2.41	2.41	2
Westgate	Cadbury	4.16	0	0	0	0	0.65	0	0	0
Gilbert	Caddy	12	0	0	0	0	3.26	3.26	3.26	3.26
Potrero	Cadena	16	3.97	3.97	3.94	3.94	8.59	6.94	6.14	5.71
Narrows	Cadillac	12	3.02	3.02	3.02	3.02	0	0	0	0
Newmark	Cadiz	4.16	0.1	0.1	0.1	0.1	1.27	0.87	0.66	0.55
Camden	Cadmium	12	0.78	0.78	0.78	0.78	2.53	2.53	2.53	2.53
Wakefield	Cadway	16	2.03	2.03	2.03	2.03	6.9	5.75	5.18	4.81
Haskell	Caesar	16	0	0	0	0	6.58	5.5	4.97	4.6
Coffee	Cafe	12	0	0	0	0	2.26	2.26	2.26	2
Padua	Cagli	12	0	0	0	0	3.24	3.24	3.24	3.24
Movie	Cagney	16	3.97	3.97	3.97	3.97	8.59	7.32	6.53	6.03
Indian Wells	Cahuilla	12	0	0	0	0	0	0	0	0
Lindsay	Cairns	12	0	0	0	0	0	0	0	0
Redlands	Cajon	4.16	0.09	0.09	0.09	0.09	1.03	0.69	0.45	0.38
Layfair	CalPoly	12	0.25	0.25	0.25	0.25	3.36	3.36	3.36	3.32
Laguna Bell	CalStrip	16	4.27	3.97	3.97	3.97	6.75	5.6	5.03	4.67
Valdez	Calabasas	16	3.35	3.35	3.35	3.35	7.28	6.27	5.58	5.09
Declez	Calabash	12	0.48	0.48	0.48	0.48	0	0	0	0
Calamar P.T.	Calamar	12	1.83	1.83	1.83	1.83	3.2	3.2	3.2	2.75
Beverly	Calarest	4.16	0.74	0	0	0	0.95	0	0	0
Calcadia P.T.	Calcadia	12	0	0	0	0	0	0	0	0
Limestone	Calcium	12	1.26	1.26	1.26	1.26	3.26	3.26	3.26	3.18
Visalia	Caldwell	12	0	0	0	0	0	0	0	0
Newhall	Calgrove	16	0	0	0	0	5.71	4.8	4.33	4.02
Palmdale	Caliber	12	0	0	0	0	2.07	2.07	1.7	1.44
Sullivan	Calico	12	1.81	1.81	1.81	1.81	3.13	3.13	3.13	3.11
Cummings	Caliente	12	2.81	2.81	2.81	2.81	3.28	3.28	2.87	2.43
Chase	California	12	0.69	0.69	0.69	0.69	2.21	2.21	2.21	1.81
Yucaipa	Calimesa	12	2.47	2.47	2.47	2.47	3.37	3.37	3.37	3.32
Barre	Calla	12	0.26	0.26	0.26	0.26	3.27	3.27	3.27	3.27
Hemet	Calland	12	6.05	6.05	0	0	3.46	3.46	3.46	3.46
Moraga	Callaway	12	0	0	0	0	2.48	2.48	2.44	1.93
Little Rock	CalliValli	12	0.99	0.99	0.99	0.99	2.96	2.94	2.33	1.98
Tipton	Callison	12	0	0	0	0	0	0	0	0
Neptune	Calm	12	0	0	0	0	3.26	3.26	3.26	3.26
Chino	Calmen	12	0	0	0	0	1.42	1.42	1.42	1.36

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Wave	Calol	12	3.65	3.46	3.46	3.46	3.44	3.44	3.44	3.44
San Dimas	Calora	12	0	0	0	0	3.25	3.25	3.25	3.25
Live Oak	Calspar	12	0.98	0.98	0.98	0.98	2.96	2.96	2.96	2.96
Shandin	Calstate	12	0.48	0.48	0.48	0.48	2.02	2.02	2.02	2
Padua	Calvo	12	0.13	0.13	0.13	0.13	2.56	2.56	2.56	2.27
Bassett	Calypso	12	4.09	3.02	3.02	3.02	3.42	3.42	3.42	3.42
Mayberry	Cambridge	12	2.12	2.12	2.12	2.12	3.27	3.27	3.27	3.19
Anita	Camellia	16	1.43	1.43	1.43	1.43	11.5	6.58	6.05	5.49
Bain	Cameo	12	1.92	1.92	1.92	1.92	2.86	2.86	2.86	2.83
Redondo	CaminoReal	4.16	1.01	0	0	0	0.77	0	0	0
Camp Angelus P.T.	CampAngelus	2.4	0.06	0	0	0	1.29	0	0	0
Camp Baldy P.T.	CampBaldy	2.4	0	0	0	0	1.29	0	0	0
Camp Nelson P.T.	CampNelson	4.16	0	0	0	0	0	0	0	0
Nugget	Campanula	25	1.5	1.5	0	0	3.08	3.08	3.08	3.08
Porterville	Campbell	12	0	0	0	0	0	0	0	0
Cottonwood	Camprock	33	19.38	12.57	12.57	8.38	27	22.47	16.15	12.52
Upland	Campus	12	0.52	0.52	0.52	0.52	3.4	3.4	3.4	3.4
Belvedere	Camy	4.16	0	0	0	0	1.12	0.76	0.5	0.5
Nelson	Canal	33	11.47	11.47	11.47	8.38	27	13.22	10.43	7.09
Tulare	Canby	12	0	0	0	0	0	0	0	0
Estrella	Cancer	12	1.5	1.5	1.5	1.5	2.89	2.89	2.86	2.42
Brea	Cancun	12	0	0	0	0	3.34	3.34	3.34	3.34
Somerset	Candle	12	0	0	0	0	2.74	2.74	2.74	2.48
Anaverde	Candleberry	12	1.66	1.66	1.66	1.66	3.23	3.23	3.23	3.23
Weldon	Canebrake	12	0	0	0	0	0	0	0	0
Lakewood	Canehill	4.16	0.14	0.14	0.14	0.14	1.05	0.58	0.44	0.37
Casitas	Canet	16	3.03	3.03	3.03	3.03	6.16	5.18	4.68	4.34
Laguna Bell	Canning	16	7.38	7.38	7.38	7.38	10.26	7.86	7.09	6.57
Bolsa	Canoe	12	3.02	3.02	3.02	3.02	3.3	3.3	3.3	2.95
Palm Canyon	Cantina	12	0	0	0	0	1.58	1.58	1.58	1.37
Los Cerritos	Canton	4.16	0	0	0	0	0.57	0	0	0
Capanero P.T.	Capanero	2.4	0	0	0	0	0	0	0	0
Costa Mesa	Cape	4.16	0.31	0.31	0.31	0.31	0.99	0.5	0.5	0.41
Triton	Capelin	12	0	0	0	0	3.19	3.19	2.8	2.36
Lucas	Capetown	12	0	0	0	0	3.48	3.48	3.48	3.48
Newmark	Capitol	4.16	0.26	0.26	0	0	1.24	0.84	0.67	0.56
Artesia	Caponhurst	4.16	0.01	0.01	0.01	0.01	1.26	0.53	0.53	0.44
Broadway	Capri	12	3.44	3.44	3.02	3.02	3.47	3.47	3.47	3.47
Estrella	Capricorn	12	9.3	9.3	3.78	3.78	3.49	3.49	3.49	3.49
Culver	Capstan	16	3.97	3.97	3.97	3.97	7.57	5.06	5.06	4.7
Car Wash P.T.	CarWash	4.16	0.66	0	0	0	1.13	0	0	0
Carancho P.T.	Carancho	12	3.46	3.02	3.02	3.02	2.54	2.45	1.95	1.65
Vestal	Caratan	12	0	0	0	0	0	0	0	0
Greening	Caravel	12	2.34	2.34	2.34	2.34	3.48	3.48	3.48	3.48
Bunker	Carbine	12	1.18	1.18	1.18	1.18	3.44	3.44	3.24	2.75
Goldtown	Carbon	12	3.02	3.02	3.02	3.02	0	0	0	0
Cardinal P.T.	Cardinal	2.4	0.12	0	0	0	0.71	0	0	0
Mt. Vernon	Carey	4.16	0	0	0	0	1.27	0.81	0.63	0.53
Lakewood	Carfax	4.16	0	0	0	0	1.04	0.43	0.43	0.36
Seabright	Cargo	12	3.07	3	3	3	3.47	3.47	3.47	3.47
Moraga	Cariso	12	0	0	0	0	3.22	3.22	3.22	2.87
San Dimas	Carlet	12	0	0	0	0	2.18	2.18	2.18	2.18
Lynwood	Carlin	4.16	0.04	0.04	0.04	0.04	1.26	0.66	0.66	0.56
Atwood	Carlton	12	3.02	0	0	0	3.32	3.32	3.32	3.32
Newcomb	Carmel	12	1.12	1.12	1.12	1.12	3.3	3.3	3.3	3.3
Shandin	Carmelita	12	0	0	0	0	3.34	3.34	2.93	2.42
Barre	Carnation	12	0	0	0	0	3.13	3.13	3.13	3.01
Gonzales	Carnegie	16	3.74	3.74	3.74	3.74	4.04	3.41	3.07	2.84
Victoria	Carnelian	16	2.53	2.53	2.53	2.53	7.77	6.62	5.95	5.46
Lighthipe	Caro	12	0.45	0.45	0.45	0.45	3.49	3.49	3.49	3.49
Parkwood	Carob	12	0	0	0	0	3.07	3.07	3.07	3.07
Del Rosa	Carpenter	12	0	0	0	0	3.45	3.45	3.45	2.99
Carpinteria	Carpoil	16	3.97	3.97	3.94	3.94	7.74	6.62	5.82	5.41
Puente	Carr	12	3.11	3.02	3.02	3.02	2.85	2.85	2.85	2.85
Silver Spur	Carriage	12	0	0	0	0	0	0	0	0
Palm Canyon	Carribean	12	2.61	2.61	2.61	2.61	2.97	2.97	2.97	2.97
Pico	Carrier	12	3.35	3.35	3.35	3	3.49	3.49	3.49	3.49
Gilbert	Cart	12	0	0	0	0	3	3	3	3
Howard	Carter	4.16	0.34	0.34	0.34	0.34	1.24	0.64	0.64	0.54
Tulare	Cartmill	12	0	0	0	0	0	0	0	0
Oxnard	Carty	4.16	1.21	1.21	0	0	0.87	0.87	0.69	0.58
Quinn	Carver	12	0	0	0	0	0	0	0	0
Redlands	CasaLoma	4.16	0.52	0	0	0	0.61	0	0	0
Wimbledon	Casals	12	0.6	0.6	0.6	0.6	3.43	3.43	3.43	2.97
Pitman	Cascada	12	0	0	0	0	0	0	0	0
Cascade P.T.	Cascade	12	0.53	0.53	0.53	0.53	1.92	1.92	1.86	1.56
Elsinore	Case	33	12.67	12.67	12.67	12.67	27	23.59	14.71	11.67
San Marcos	Casey	16	2.39	2.39	2.39	2.39	7.36	6.27	5.7	5.14
Alder	Casmalia	12	0	0	0	0	0	0	0	0
Cameron	Caspian	12	3.02	3	3	3	3.47	3.47	3.47	3.47

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Santa Susana	Cassidy	16	1.81	1.81	1.81	1.81	8.16	6.9	6.17	5.73
Gisler	Cassini	12	4.99	4.99	3.02	3.02	3.49	3.49	3.49	3.49
Modoc	Castillo	4.16	0.76	0	0	0	0.62	0	0	0
Castle P.T.	Castle	4.16	0.94	0	0	0	1.07	0	0	0
Edwards	CastleButte	33	0	0	0	0	0	0	0	0
Big Bend Bia	Castlerock	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Wakefield	Castro	16	3.97	3.97	3.97	3.94	6.08	5.1	4.62	4.26
Fremont	Caswell	16	2.98	2.98	2.98	2.98	9.11	7.56	6.83	6.35
Redondo	Catalina	4.16	0.41	0.41	0.41	0.41	1.13	0.68	0.53	0.45
Alon	Catalytic	12	9.36	0	0	0	3.49	3.49	3.49	3.49
San Dimas	Cataract	12	3.46	3.46	3.46	3.46	3.3	3.3	3.3	3.28
Declez	Catawba	12	0	0	0	0	3.36	3.36	2.96	2.5
Roadway	Caterpillar	12	2.97	0	0	0	3.49	3.18	2.53	2.14
Bayside	Catfish	12	0.64	0.64	0.64	0.64	2.95	2.95	2.95	2.95
La Veta	Cathy	12	0	0	0	0	3.23	3.23	3.23	3.23
Tenaja	Catt	12	5.09	0	0	0	3.21	3.21	3.21	3.03
Tulare	Cattle	12	0	0	0	0	0	0	0	0
Team	Cavaliers	12	3.02	0	0	0	3.49	0	0	0
Garfield	Cawston	4.16	0.16	0.16	0.16	0.16	1.19	0.79	0.61	0.52
Bryan	Caymen	12	0	0	0	0	3.39	3.39	3.39	3.35
O'neill	Caza	12	0	0	0	0	3.4	3.4	3.4	3.4
Delano	Cecil	4.16	0	0	0	0	0	0	0	0
Colorado	Cedar	4.16	0.33	0	0	0	0.64	0	0	0
Burnt Mill	CedarGlen	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Cedar Pines P.T.	CedarPines	2.4	0.12	0.12	0	0	1.28	0.92	0.71	0.6
Sun City	Celestial	12	2.59	2.59	2.59	2.59	2.92	2.92	2.92	2.92
Elizabeth Lake	Cello	16	3.4	3.4	3.4	3.4	7.9	5.66	5.12	4.68
Team	Celtics	12	0	0	0	0	3.06	3.06	3.06	3.06
Victor	Cement	33	9.12	8.38	8.38	8.38	13.32	8.21	8.21	6.49
San Bernardino	Centaur	12	0.67	0.67	0.67	0.67	0	0	0	0
Santiago	Centavo	12	0	0	0	0	3.32	0	0	0
Inglewood	Centinela	16	3.97	3.97	3.97	3.94	8.19	7.18	6.32	5.74
Haskell	Centurion	16	1.9	1.9	1.9	1.9	4.89	4.03	3.73	3.38
Lennox	Century	4.16	0	0	0	0	1.23	0.67	0.52	0.44
Temescal P.T.	Ceramic	4.16	0.88	0	0	0	0.68	0	0	0
Skylark	Cereal	12	2.42	2.42	2.42	2.42	3.16	2.25	2.25	1.9
Daisy	Cero	4.16	0.56	0.56	0.56	0.56	1.25	1.02	0.67	0.57
Chase	Cerrito	12	0	0	0	0	2.87	2.87	2.87	2.87
Mesa	Cerveza	16	0.46	0.46	0.46	0.46	7.49	6.08	5.5	5.1
Stetson	Cessna	12	0	0	0	0	2.97	2.97	2.97	2.97
Ganesha	Ceylon	12	1.72	1.72	1.72	1.72	2.84	2.84	2.57	2.18
Moraga	Chablis	12	0	0	0	0	3.49	3.49	2.91	2.38
Brighton	Chadron	16	2.93	2.93	2.93	2.93	8.9	7.4	6.68	6.2
Upland	Chaffey	12	3.02	3.02	3	3	3.48	3.48	3.48	3.48
Chalet P.T.	Chalet	2.4	0.5	0	0	0	0.83	0	0	0
Zack	Chalfant	12	0	0	0	0	0	0	0	0
Gisler	Challenger	12	3.02	3.02	0	0	3.49	3.49	3.49	3.49
Peyton	Champion	12	0.51	0.51	0.51	0.51	3.2	3.2	3.2	2.79
Redlands	Chandler	4.16	0.07	0	0	0	0.83	0	0	0
Bunker	Chaney	12	1.42	1.42	1.42	1.42	0	0	0	0
Wimbledon	Chang	12	0.06	0.06	0.06	0.06	2.23	2.23	2.23	2.11
Rush	Change	16	0.06	0.06	0.06	0.06	8.9	7.21	6.5	6.04
Pico	Channel	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Blythe City	Chanslor	33	8.38	8.38	0	0	0	0	0	0
Arcadia	Chantry	16	0	0	0	0	7.76	6.56	5.88	5.46
Santa Barbara	Chapala	4.16	1.01	1.01	0	0	1.29	1.13	0.69	0.57
Michillinda	Chapman	4.16	0.81	0.81	0.81	0.81	1.05	0.61	0.44	0.37
Pauba	Chardonnay	12	2.36	2.36	2.36	2.36	1.62	1.36	1.08	0.91
Slater	Chargers	12	2.33	2.33	2.33	2.33	3.12	3.12	3.12	2.9
Haskell	Chariot	16	0	0	0	0	8.62	5.11	4.62	4.25
Longdon	Charity	4.16	0.52	0.52	0.52	0.52	1.14	0.81	0.64	0.49
Cathedral City	Charlesworth	4.8	0	0	0	0	0.47	0.34	0.26	0.22
Olympic	Charleville	4.16	1.01	1.01	1.01	1.01	1.29	0.88	0.69	0.58
Alder	Charlie	12	0	0	0	0	3	3	3	2.59
Mayberry	Charlton	12	0	0	0	0	3.16	3.16	3.16	2.94
Orange	Chartreuse	12	1.23	1.23	1.23	1.23	3.46	3.46	3.46	3.46
Casa Diablo	Chateau	33	0	0	0	0	0	0	0	0
Tennessee	Chattanooga	12	2.36	2.36	2.36	2.36	3.08	3.08	3.08	2.44
Baker	Chavez	12	0	0	0	0	0	0	0	0
Pechanga	Chawa	12	1.18	1.18	1.18	1.18	1.58	1.08	0.84	0.71
Stadler	Cheerleader	12	1.65	1.65	1.65	1.65	2.97	2.97	2.97	2.97
Tulare	Cheese	12	0	0	0	0	0	0	0	0
Lampson	Cheetah	12	0	0	0	0	3.37	3.37	3.37	3.37
Walnut	Chella	12	0	0	0	0	3.17	3.17	3.17	2.68
Colorado	Chelsea	4.16	0	0	0	0	0.75	0.47	0.37	0.31
Sepulveda	Chemical	16	3.97	0	0	0	7.49	0	0	0
Topanga	Cheney	4.16	1.01	0	0	0	0.75	0	0	0
MacArthur	Chenualt	12	1.11	1.11	1.11	1.11	3.26	3.26	3.23	2.71
Shawnee	Cherokee	12	0	0	0	0	2.61	2.61	2.33	1.98
State Street	Chestnut	12	7.65	3.02	3.02	3	3.49	3.49	3.49	3.49

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Culver	Cheviot	4.16	0	0	0	0	1.15	0.69	0.51	0.43
Shuttle	Chewbacca	12	0.12	0.12	0.12	0.12	1.7	1.7	1.7	1.43
Shawnee	Cheyenne	12	3.02	0	0	0	3.45	0	0	0
Tamarisk	Chia	12	0	0	0	0	0	0	0	0
Belvedere	Chicago	4.16	0	0	0	0	0.6	0	0	0
Rolling Hills	Chico	16	3.97	3.97	3.97	3.97	7.56	5.65	5.1	4.72
Ely	Chile	12	0	0	0	0	3.4	3.4	3.4	3.4
Chillon P.T.	Chillon	2.4	0.28	0	0	0	1.09	0	0	0
Jefferson	Chimay	12	1.76	1.76	1.76	1.76	3.42	3.42	3.24	2.72
Ganesha	Chime	12	1.8	1.8	1.8	1.8	3.36	3.36	3.36	3.29
Modena	China	12	0	0	0	0	3.38	3.38	3.38	3.38
Lunar	ChinaPeak	12	0	0	0	0	0	0	0	0
Liberty	Chinowth	12	0	0	0	0	0	0	0	0
Gilbert	Chipper	12	0.11	0.11	0.11	0.11	3.24	3.24	2.97	2.49
Shawnee	Chippewa	12	0.02	0.02	0.02	0.02	2.9	2.9	2.9	2.67
Shawnee	Choctaw	12	2.31	0	0	0	3.33	3.33	3.33	3.33
Apple Valley	Choiceanna	12	0	0	0	0	3.05	3.05	3.05	2.86
Mescalero P.T.	Cholla	4.8	0.11	0	0	0	0.65	0	0	0
Chollita P.T.	Chollita	12	1.56	1.56	1.56	1.56	3.09	3.09	3.09	3.09
Watson	Chris	12	2.19	2.19	2.19	2.19	3.21	3.21	3.21	3.02
La Veta	Christine	12	1.05	1.05	1.05	1.05	3.06	3.06	3.06	2.74
Lark Ellen	Christy	12	0.06	0	0	0	3.47	0	0	0
Limestone	Chrome	12	0	0	0	0	3.14	3.14	3.14	3.14
Laguna Bell	Chrysler	16	7.07	3.97	3.97	3.97	9.64	8.07	7.24	6.73
Ivyglen	ChuckWagon	12	0	0	0	0	2.47	2.47	2	1.65
Eagle Mountain	Chuckawalla	12	0	0	0	0	0	0	0	0
Ramona	Chucker	4.16	0.16	0.16	0.16	0.16	1.28	0.96	0.67	0.56
Malibu	Chumash	16	6.64	3.97	3.97	3.97	8.77	7.24	6.35	5.87
Gallatin	Church	12	3.71	0	0	0	3.37	0	0	0
MacArthur	Churchill	12	2.88	2.88	2.88	2.88	0	0	0	0
Verdant	Cibola	12	2.39	2.39	2.39	2.39	3.26	2.34	1.52	1.26
Santa Barbara	Cienigitas	16	3.97	3.97	3.97	3.97	8.07	6.63	6.1	5.56
Inglewood	Cimarron	16	3.97	3.97	3.97	3.97	7.51	6.16	5.56	5.16
Coso	Cinder	12	0	0	0	0	0	0	0	0
Oak Springs P.T.	Circle	12	0.37	0.37	0.37	0.37	3.48	3.48	3.48	3.48
San Miguel	Cisco	16	5.96	5.96	3.97	3.97	8.4	7.11	6.27	5.82
Aqueduct	Cistern	12	1.56	1.56	1.56	1.56	1.19	0.94	0.74	0.62
Signal Hill	Citizens	12	2.12	0	0	0	3.4	0	0	0
Declez	Citrow	12	0.29	0.29	0.29	0.29	3.17	3.17	2.89	2.44
Highland	CityCreek	12	0.07	0.07	0.07	0.07	3.27	3.27	3.27	3.05
Banning	CityOfBanning#1	33	8.38	8.38	0	0	27	27	27	27
Banning	CityOfBanning#2	33	8.38	8.38	8.38	8.38	27	27	23.03	18.25
Anaverde	CityRanch	12	1.12	1.12	1.12	1.12	3.45	3.45	3.23	2.67
Banning	CityofBanning#3	33	3.78	0	0	0	27	0	0	0
Wave	Civic	4.16	0.99	0	0	0	0.78	0	0	0
Twentynine Palms	CivicCenter	4.8	0.1	0.1	0.1	0.1	1.17	0.72	0.57	0.48
Cypress	Clair	12	0	0	0	0	3.48	3.48	3.48	3.48
Porterville	Clampett	12	0	0	0	0	0	0	0	0
Oak Grove	Clancy	12	0	0	0	0	0	0	0	0
Cudahy	Clara	4.16	0	0	0	0	1.29	1.06	0.67	0.56
Elizabeth Lake	Clarinet	16	1.28	1.28	1.28	1.28	5.1	4.66	3.89	3.54
Marion	Claudia	12	1.67	1.67	1.67	1.67	3.24	3.24	3.24	3.24
Wave	Clay	12	2.02	0	0	0	3.42	0	0	0
Peerless	Claymine	12	0	0	0	0	0	0	0	0
Rosemead	Clayton	16	1.24	1.24	1.24	1.24	7.95	6.77	6.01	5.59
Washington	Cleat	12	2.74	2.74	2.74	2.74	3.43	3.43	3.43	3.43
Naomi	Clemont	4.16	0.08	0	0	0	0.6	0	0	0
Somis	Clemson	16	7.83	0	0	0	7.57	6.43	5.67	5.27
Ditmar	Cleo	4.16	0.38	0.38	0.38	0.38	1.15	0.8	0.62	0.51
Cornuta	Clerk	12	5.24	5.24	3.02	3.02	3.39	3.39	3.39	3.39
O'neill	Cleveland	12	0	0	0	0	2.91	2.66	2.14	1.77
Costa Mesa	Cliff	4.16	0.51	0	0	0	0.6	0	0	0
Stewart	Clifford	12	0.48	0.48	0.48	0.48	3.46	3.46	3.46	3.4
Redondo	Clifton	4.16	0.44	0.44	0.44	0.44	1.09	0.82	0.59	0.48
Porterville	Cline	4.16	0	0	0	0	0	0	0	0
Timoteo	Clinic	12	2.8	0	0	0	3.49	3.49	3.49	3.49
Nelson	Clinton	33	6.79	6.79	6.79	6.79	27	27	27	27
Lunada	Clipper	4.16	1.01	0	0	0	1.28	0	0	0
Poplar	Cloer	12	0	0	0	0	0	0	0	0
Moreno	Clove	12	1.55	1.55	1.55	1.55	3.03	3.03	2.74	2.33
Barre	Clover	12	0	0	0	0	3.24	3.24	3.24	3.07
Ocean Park	Cloverfield	4.16	0.26	0.26	0.26	0.26	0.73	0.43	0.34	0.29
Temple	Cloverly	4.16	0	0	0	0	0.72	0	0	0
Cardiff	ClubOaks	33	1.73	1.73	1.73	1.73	27	24.09	17.71	12.63
Santa Rosa	Clubhouse	12	0	0	0	0	0	0	0	0
Narod	Clutch	12	0	0	0	0	3.26	3.26	3.08	2.6
Auld	Clydesdale	12	0.53	0.53	0.53	0.53	2.95	2.95	2.36	1.96
Placentia	Coach	12	0.78	0.78	0.78	0.78	3.14	3.14	3.14	2.72
Garnet	Coachella	33	7.82	7.82	7.82	7.82	0	0	0	0
Limestone	Coal	12	2.33	2.33	2.33	2.33	3.37	3.37	3.37	3.29

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Victor	Coalinga	12	2.23	2.23	2.23	2.23	3.13	3.13	2.72	2.29
Crown	Coastal	12	1.34	1.34	1.34	1.34	3.21	3.21	2.92	2.47
Camden	Cobalt	12	0.01	0.01	0.01	0.01	3.03	3.03	3.03	3.03
North Oaks	Cobra	16	3.97	3.97	3.97	3.97	8.96	7.62	6.82	6.3
Bryan	Cocamo	12	0	0	0	0	3.23	3.23	3.23	3.17
Apple Valley	Cochise	12	4.75	3.02	3.02	3.02	3	2.85	2.16	1.83
Chestnut	Coco	12	1.48	1.48	1.48	1.48	3.48	3.48	3.48	3.48
Pierpont	Code	4.16	0.54	0.54	0.54	0.54	1.17	0.81	0.68	0.53
Walteria	Codona	4.16	0.31	0.31	0.31	0.31	0.78	0.53	0.4	0.33
Pioneer	Cody	12	0.58	0.58	0.58	0.58	3.44	3.44	3.44	3.1
Bartolo	Coffee	4.16	0.72	0	0	0	0.66	0	0	0
Chiquita	Cognac	12	3.33	3.33	3.33	3.02	3.44	3.44	3.44	3.02
Amador	Cogswell	4.16	0	0	0	0	1.21	0.81	0.61	0.51
Gaviota	Cojo	16	9.14	0	0	0	8.3	7.03	5.53	5.03
Arro	Cola	4.16	0.28	0	0	0	0.65	0	0	0
Upland	Colburn	4.16	0.07	0.07	0	0	1.23	0.86	0.71	0.58
Coldbrook P.T.	Coldbrook	4.16	0.81	0	0	0	1.29	0	0	0
Beverly	Coldwater	4.16	0	0	0	0	1.18	0.48	0.48	0.4
Michillinda	Cole	4.16	0	0	0	0	1.18	0.72	0.58	0.47
La Habra	Colfax	12	0	0	0	0	3.39	3.39	3.39	3.39
San Antonio	Colgate	12	0.38	0.38	0.38	0.38	2.52	2.52	2.52	2.5
Stadium	Coliseum	12	2.67	2.67	2.67	2.67	3.43	3.43	3.43	3.34
Randall	Colleen	12	0	0	0	0	3.14	3.14	3.14	2.92
Upland	CollegePark	4.16	0	0	0	0	0.94	0.6	0.47	0.4
Moulton	Collie	12	0.49	0.49	0.49	0.49	3.36	3.36	3.36	3.36
Elsinore	Collier	12	0	0	0	0	1.92	1.92	1.66	1.38
Moorpark	Collins	16	0.74	0.74	0.74	0.74	4.83	4.83	4.36	4.05
East Barstow	Color	4.16	0	0	0	0	0	0	0	0
Auld	Colt	12	1.7	1.7	1.7	1.7	3.35	3.35	3.35	3.13
Amador	Columbia	4.16	0	0	0	0	0.62	0.62	0.62	0.51
Bullis	Colyer	16	0	0	0	0	5.47	4.56	4.08	3.78
Shawnee	Comanche	12	0	0	0	0	3.05	3.05	2.86	2.41
Eisenhower	Combat	12	0	0	0	0	2.86	2.86	2.81	2.34
Chino	Comet	12	3.02	3	3	3	3.3	3.3	3.3	3.3
Monrovia	Commercial	4.16	0	0	0	0	0.69	0	0	0
Alhambra	Commonwealth	4.16	0	0	0	0	0.96	0.71	0.51	0.43
Perry	Como	4.16	0.48	0	0	0	1.14	0.8	0.62	0.52
Fullerton	Complex	12	1.19	1.19	1.19	1.19	3.28	3.28	3.28	3.28
Sepulveda	Computer	16	3.97	3.97	0	0	9.18	8.14	7.14	6.46
Lucas	Conant	12	1.29	1.29	1.29	1.29	2.76	2.76	2.76	2.46
Gaviota	Concepcion	16	3.97	3.97	3.97	3.97	5.35	4.43	4.01	3.71
Monrovia	Concord	4.16	0	0	0	0	1.17	0.71	0.56	0.47
Vail	Concourse	16	0	0	0	0	8.41	7.08	6.37	5.91
Dalton	Concrete	12	3.02	0	0	0	3.49	0	0	0
Malibu	Conejo	16	1.98	1.98	1.98	1.98	7.44	6.09	5.47	5.08
Ivyglen	Conestoga	12	1.92	1.92	1.92	1.92	3.15	3.15	3.02	2.56
Forest Home	Conference	2.4	0.02	0	0	0	0.94	0	0	0
Francis	Congo	12	0	0	0	0	3.14	3.14	3.14	2.96
Cornuta	Congress	12	3.33	3.33	3.33	3.02	3.48	3.48	3.48	3.48
Oak Park	Conifer	16	0	0	0	0	7.27	5.84	5.31	4.9
Yucaipa	Conine	12	4	4	3.02	3.02	2.96	2.96	2.8	2.35
Corum	Conley	12	3.02	3.02	3.02	3.02	3.46	2.42	1.68	1.43
Carolina	Connecticut	12	0	0	0	0	3.44	3.44	3.44	3.44
Wimbledon	Conners	12	2.81	2.81	2.81	2.81	2.1	2.1	2.1	2.1
Bain	Conning	12	0	0	0	0	3.19	3.19	3.19	2.61
Viejo	Consejo	12	2.18	2.18	2.18	2.18	3.4	3.4	3.4	3.03
Haskell	Constantine	16	0	0	0	0	5.96	4.7	4.22	3.91
Holgate	Conte	12	0	0	0	0	0	0	0	0
Sepulveda	Continent	16	1.6	0	0	0	7.11	0	0	0
Naomi	Converse	4.16	0.3	0	0	0	0.96	0	0	0
Fruitland	Convex	16	11.29	0	0	0	13.2	0	0	0
Industry	Conveyor	12	0.39	0.39	0.39	0.39	3.37	3.37	3.37	2.85
Lundy	Conway	16	0	0	0	0	0	0	0	0
Stadium	Cony	12	3.02	3	3	3	3.27	3.27	2.9	2.45
Visalia	Conyer	4.16	0	0	0	0	0	0	0	0
Chiquita	Cooler	12	2.64	2.64	2.64	2.64	3.18	3.18	2.6	2.18
Colton	Cooley	12	2.11	2.11	2.11	2.11	3.33	3.33	3.33	3.33
Tipton	Cooper	12	0	0	0	0	0	0	0	0
Bandini	Copper	16	4.89	3.97	3.97	3.97	13.2	7.83	7.05	6.54
North Oaks	Copperhead	16	6.59	3.94	3.94	3.94	9.53	7.63	6.82	6.33
Moneta	Copra	4.16	0.94	0	0	0	0.68	0	0	0
Bassett	Corak	12	3.02	3.02	3.02	3.02	3.46	3.46	3.46	3.46
Topaz	Coral	4.16	1.56	1.01	1.01	1.01	1.16	0.63	0.63	0.51
Bayside	Corbina	12	0.86	0.86	0.86	0.86	3.36	3.36	3.36	3.36
Eric	Corby	12	0.18	0.18	0.18	0.18	2.92	2.92	2.92	2.74
Beverly	Cord	4.16	1.08	0	0	0	0.82	0	0	0
Hanford	Cordial	12	0	0	0	0	0	0	0	0
Santiago	Cordoba	12	2.56	2.56	2.56	2.56	3.49	3.49	3.49	3.49
Archline	Cordon	12	0	0	0	0	3.27	3.27	3.27	3.27
Granada	Cordova	4.16	0.21	0.21	0.21	0.21	0.96	0.63	0.49	0.42

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Tenaja Test	Corinth	12	1.7	1.7	1.7	1.7	2.88	2.88	2.88	2.53
Lakeside P.T.	Cornell	4.16	1.01	0	0	0	1.01	0	0	0
Lynwood	Cornish	4.16	0.06	0.06	0.06	0.06	1.18	0.75	0.6	0.5
Chestnut	Cornnut	12	3.02	3.02	3.02	3.02	3.29	3.29	3.29	3.29
Narrows	Cornwall	12	1.21	1.21	1.21	1.21	2.64	2.64	2.64	2.44
Mesa	Coronado	16	3.38	0	0	0	7.02	0	0	0
Jefferson	Coronita	12	0.47	0.47	0.47	0.47	3.29	3.29	2.98	2.53
Bunker	Corporal	12	0	0	0	0	3.35	3.35	3.35	2.9
Belmont	Corral	4.16	0.15	0	0	0	0.63	0	0	0
Corrigan P.T.	Corrigan	2.4	0	0	0	0	1.25	0	0	0
Los Cerritos	Corrine	4.16	0.1	0.1	0.1	0.1	1.02	0.59	0.46	0.39
Stetson	Corsair	12	0	0	0	0	1.29	0.87	0.69	0.58
Gonzales	Corsica	16	0.25	0.25	0.25	0.25	6.21	5.22	4.7	4.37
Victorville	Corta	4.16	1.01	0	0	0	0.94	0	0	0
Morro	Cortese	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Narrows	Corvette	12	0	0	0	0	3.49	0	0	0
Beverly	Cory	16	2.86	2.86	2.86	2.86	7.87	6.41	5.78	5.37
Santa Rosa	Costello	33	0	0	0	0	0	0	0	0
Larder	Cota	4.16	0.23	0	0	0	0.75	0	0	0
Cottage Grove	CottageGrove	2.4	0.07	0	0	0	0.67	0	0	0
Poplar	Cotton	12	0	0	0	0	0	0	0	0
North Oaks	Cottonmouth	16	0	0	0	0	8.2	5.71	5.08	4.69
Lampson	Cougar	12	0.74	0	0	0	3.49	0	0	0
Beverly	CountryClub	4.16	0.78	0	0	0	0.79	0	0	0
Walnut	Countrywood	12	0	0	0	0	3.41	3.41	3.41	3.01
Watson	County	12	5.85	0	0	0	3.49	3.49	3.49	3.49
Railroad	Coupler	12	0	0	0	0	3.29	3.29	3.29	2.89
Placentia	Course	12	0	0	0	0	3.46	3.46	3.46	3.46
Palmdale	Courson	12	1.44	0	0	0	1.87	1.87	1.87	1.65
Locust	Court	4.16	1.01	0	0	0	1.04	0	0	0
Marine	Courtland	16	3.97	3.97	3.97	3.97	9.23	7.91	6.97	6.39
Cove P.T.	Cove	12	3.3	3.3	3.3	3.3	3.46	3.46	3.22	2.59
Thousand Oaks	Coventry	16	0.16	0.16	0.16	0.16	6.11	5.15	4.63	4.3
Marymount	Coveview	16	4.96	3.94	3.94	3.94	8.26	5.69	4.93	4.53
Railroad	Cowcatcher	12	0.59	0.59	0.59	0.59	3.35	3.35	3.35	3.35
Mt. Vernon	Cowen	4.16	0.33	0.33	0.33	0.33	1.28	0.84	0.75	0.56
State Street	Cowles	12	7.35	4.21	4.21	3.02	3.47	3.47	3.47	3.47
Bowl	Cox	12	2.67	2.67	2.67	2.67	3.45	3.45	3.45	3.45
Somerset	Coyote	12	3.02	3.02	3.02	3	3.46	3.46	3.46	3.46
Arrowhead	Crab	33	5.32	5.32	5.32	5.32	27	20.73	14.51	11.26
Saugus	Crabtree	16	2.16	2.16	2.16	2.16	6.94	5.59	5.07	4.68
Homart	Craftsman	12	8.05	8.05	0	0	3.49	3.49	3.49	3.49
Highland	Cram	12	0.91	0.91	0.91	0.91	2.71	2.71	2.71	2.71
Yukon	Cranbrook	4.16	1.05	1.05	1.01	1.01	1.23	0.76	0.6	0.51
Compton	Crane	4.16	0.42	0.42	0.42	0.42	1.27	0.8	0.62	0.53
Cudahy	Creamery	16	3.97	3.97	3.97	3.97	9.2	6.93	6.29	5.81
Oak Grove	Cree	12	0	0	0	0	0	0	0	0
Archibald	Creekside	12	3.04	3.04	3.02	3	3.27	3.27	2.8	2.37
Moneta	Crenshaw	4.16	0.66	0.66	0.66	0.66	1.27	0.59	0.59	0.49
Tamarisk	Creosote	12	0	0	0	0	0	0	0	0
Fairfax	Crescent	4.16	0.59	0.59	0.59	0.59	0.77	0.77	0.63	0.49
Gould	Crescenta	16	0	0	0	0	4.33	3.64	3.28	3.04
Alhambra	Cresta	16	0.3	0.3	0.3	0.3	8.66	7.26	6.55	6.06
Oak Park	Cresthaven	16	2.24	2.24	2.24	2.24	6.54	5.48	4.92	4.57
Huston	Crestline	2.4	0.06	0.06	0.06	0.06	0.83	0.55	0.45	0.37
Crestwind U.G.S.	Crestwind	4.16	0.93	0	0	0	0.58	0	0	0
Liberty	Crestwood	12	0	0	0	0	0	0	0	0
Cortez	Crevolin	12	3.1	3.1	3.1	3.02	3.24	3.24	3.24	3.24
Johanna	Cribbage	12	1.65	0	0	0	3.49	0	0	0
Sunny Dunes	Crocker	4.16	0	0	0	0	0.69	0	0	0
Graham	Crockett	4.16	0	0	0	0	1.27	0.91	0.7	0.59
Yucaipa	Croft	12	0.29	0.29	0.29	0.29	3.18	3.18	3.18	2.68
Irvine	Cromwell	12	0	0	0	0	3.23	3.23	3.23	2.76
Hamilton	Cronin	12	3.26	3.02	3.02	3	2.81	2.81	2.61	2.2
Fair Oaks	Crosby	4.16	0	0	0	0	1.03	0.59	0.42	0.36
Newhall	Cross	16	2.03	2.03	2.03	2.03	8.02	6.74	5.9	5.47
Eisenhower	Crossley	33	8.38	8.38	8.38	8.38	27	27	27	25.6
Camarillo	Crosson	16	0	0	0	0	4.97	4.16	3.75	3.48
Cabrillo	Crosstown	12	3.59	0	0	0	3.49	0	0	0
Lancaster	Crowder	12	2.48	2.48	2.48	2.48	0	0	0	0
Casa Diablo	Crowley	12	0	0	0	0	0	0	0	0
Pechanga	Crownhill	12	2.65	2.65	2.65	2.65	2.87	2.87	2.87	2.65
Atwood	Crowther	12	2.25	2.25	2.25	2.25	3.33	3.33	3.33	3.33
Malibu	Crumner	16	0	0	0	0	7.21	5.98	5.39	5.01
Crump P.T.	Crump	12	0.94	0	0	0	3.48	0	0	0
Downs	Crumville	12	0	0	0	0	0	0	0	0
Center	Crusade	12	0.87	0.87	0.87	0.87	2.76	2.76	2.71	2.3
Moraga	Cruz	12	1.11	1.11	1.11	1.11	2.85	2.85	2.77	2.34
Wave	Crystal	4.16	1.01	0	0	0	0.66	0	0	0
Ely	Cuba	12	2.51	2.51	2.51	2.51	3.49	3.49	3.49	3.49

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Edinger	Cubbon	4.16	0.6	0	0	0	0.67	0	0	0
Upland	Cubic	12	0.9	0.9	0.9	0.9	3.41	3.41	3.41	3.13
Cummings	Cuddeback	12	3.02	3.02	3.02	3.02	2.86	2.06	1.61	1.37
Milliken	Cuervo	12	3.46	3.02	0	0	3.49	3.49	3.25	2.72
Proctor	Cupid	12	0	0	0	0	3.3	3.3	3.3	3.3
Corona	Cupples	33	16.17	16.17	8.38	8.38	25.85	25.85	25.85	22.51
Ontario	Curran	4.16	0.29	0.29	0.29	0.29	1.26	1	0.65	0.54
Goshen	Curtis	12	0	0	0	0	0	0	0	0
Cottonwood	Cushenbury	33	0	0	0	0	27	18.33	18.33	18.33
Latigo	Cuthbert	16	4.53	3.97	3.97	3.97	6.47	5.08	4.58	4.25
Visalia	Cutler	12	0	0	0	0	0	0	0	0
Cudahy	Cyanide	16	3.25	3.25	3.25	3.25	7.15	5.95	5.42	4.99
Yorba Linda	Cyclone	12	0	0	0	0	2.82	2.82	2.82	2.82
Proctor	Cyclops	12	3.13	3.13	3.02	3.02	3.33	3.33	3.33	3.33
Ditmar	Cylinder	16	1.15	1.15	1.15	1.15	8.92	7.5	6.84	6.28
Niguel	Cymbal	12	2.48	2.48	2.48	2.48	3.45	3.3	3.3	2.77
Beverly	Cynthia	4.16	0.79	0.79	0.79	0.79	1.29	0.65	0.65	0.54
Colorado	Cyrus	16	0.47	0	0	0	7.03	0	0	0
Moulton	Dachshund	12	0.45	0.45	0.45	0.45	3.44	3.44	3.44	2.93
Barre	Daffodil	12	1.59	1.59	1.59	1.59	3.39	3.39	3.39	2.89
Hathaway	Daggett	4.16	1	0	0	0	0.63	0	0	0
Rolling Hills	Dahlia	4.16	0.97	0.97	0.97	0.97	1.1	0.72	0.57	0.48
Hinkley	Dairy	12	0	0	0	0	0	0	0	0
Chino	Dairyman	12	5.45	5.45	5.45	5.45	3.49	3.49	3.49	3.49
Carolina	Dakota	12	0	0	0	0	3	3	3	3
Carson	Dalberg	16	3.97	3.97	3.97	3.97	6.91	6.91	6.91	6.39
Brighton	Daleside	16	3.97	3.97	3.97	3.97	8.6	7.22	6.47	6.02
Trask	Dallas	12	0.47	0.47	0.47	0.47	3.34	3.34	3.34	2.83
Firehouse	Dalmatian	12	0.51	0.51	0.51	0.51	3.35	3.35	3.35	2.96
Dalton	Dameral	12	1.28	1.28	1.28	1.28	3.43	3.43	3.43	3.43
Jefferson	Dana	12	0	0	0	0	3.31	0	0	0
Camino	Danby	16	0.86	0.86	0.86	0.86	4.7	4.01	3.5	3.25
San Gabriel	Danes	4.16	0.27	0	0	0	0.7	0	0	0
Etiwanda	Dangerfield	12	1.49	1.49	1.49	1.49	2.9	2.9	2.27	1.9
Beverly	Daniels	16	3.97	0	0	0	7.25	0	0	0
Archibald	Danish	12	0.49	0.49	0.49	0.49	2.44	2.44	2.44	2.08
Rio Hondo	Danube	12	0.21	0.21	0.21	0.21	3.45	3.26	3.26	2.77
Morningside	Darby	4.16	0.16	0	0	0	0.68	0	0	0
Amador	Daroca	16	3.97	3.97	3.97	3.97	8.95	7.6	6.79	6.26
La Mirada	Dart	12	4.89	3.02	3.02	3.02	3.11	3.11	3.11	3.11
Mayberry	Dartmouth	12	0.19	0.19	0.19	0.19	1.6	1.54	1.15	0.97
Ellis	Darwin	12	0	0	0	0	3.47	3.47	3.47	3.19
Lucas	Dashwood	4.16	0.16	0	0	0	1.17	0.98	0.59	0.49
Olive Lake	Date	12	6.05	3.02	2.07	2.07	0	0	0	0
Farrell	DatePalm	12	0	0	0	0	2.39	2.39	1.99	1.69
Solemint	Davenport	16	3.95	3.95	3.95	3.95	4.42	3.69	3.33	3.1
Vail	Davie	16	0.89	0.89	0.89	0.89	9.45	7.88	7.12	6.61
Beverly	Dayton	4.16	0.08	0	0	0	0.92	0	0	0
Oak Grove	DeCamp	12	0	0	0	0	0	0	0	0
Corona	DeMari	4.16	1.01	0	0	0	0.69	0	0	0
Kagle Canyon P.T.	DeMille	4.16	0.28	0	0	0	0.7	0	0	0
Soquel	Deacano	12	2.99	2.99	2.99	2.99	0.55	0.55	0.55	0.55
Valley	Deacon	12	1.23	1.23	1.23	1.23	3.03	2.9	2.28	1.94
Phelan	Dealer	12	2.67	2.67	2.07	2.07	0	0	0	0
Lark Ellen	Deanna	12	0.07	0.07	0.07	0.07	3.39	3.39	3.39	3.21
Redlands	Dearborn	12	0.95	0.95	0.95	0.95	3.31	3.31	3.31	3.31
Santa Monica	Deauville	4.16	1.4	0	0	0	0.82	0	0	0
Felton	Deborah	16	3.97	3.97	3.97	3.97	8.83	7.42	6.67	6.19
Santa Monica	Debug	16	0	0	0	0	9.42	8.11	7.1	6.59
Clark	Decca	4.16	0.3	0.3	0.3	0	1.01	0.66	0.52	0.44
Passons	Decosta	12	1.56	1.56	1.56	1.56	3.44	3.44	3.44	3.44
Center	Decoy	12	1.36	1.36	1.36	1.36	3.43	3.43	3.43	3.43
South Gate	Deeble	4.16	0.93	0	0	0	1.08	0	0	0
Nelson	Deegan	12	3.61	0	0	0	3.38	0	0	0
Indian Wells	DeepCanyon	12	0	0	0	0	0	0	0	0
Apple Valley	DeepCreek	12	1	1	1	1	2.36	2.36	2.36	2.14
Terra Bella	Deer	12	0	0	0	0	0	0	0	0
Ravendale	Deerfield	16	0	0	0	0	7	5.87	5.3	4.92
Downs	Deeter	12	0	0	0	0	0	0	0	0
Deigaard P.T.	Deigaard	4.16	0	0	0	0	1.29	0	0	0
Peyton	DelCarbon	12	1.53	1.53	1.53	1.53	3.16	3.16	2.55	2.14
Second Avenue	DelJuan	12	2.97	2.97	2.97	2.97	3.44	3.44	3.31	2.78
San Gabriel	DelMar	4.16	0	0	0	0	0.62	0	0	0
Playa	DelRey	4.16	0.91	0.91	0.91	0.91	1	0.59	0.47	0.39
Amalia	Delarro	4.16	0.67	0	0	0	1.03	0	0	0
Colorado	Delaware	16	3.46	3.46	3.46	3.46	7.54	6.31	5.69	5.29
La Palma	Delco	12	2.11	2.11	2.11	2.11	3.41	3.41	3.41	3.41
Bradbury	Delford	16	0	0	0	0	8.5	7.13	6.37	5.93
Fairview	Delhi	12	0	0	0	0	3.48	3.48	3.48	3.48
Moneta	Delid	4.16	0.13	0.13	0.13	0.13	1.21	0.82	0.64	0.54

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Apple Valley	Deloro	12	1.25	1.25	1.25	1.25	2.85	2.64	2.09	1.77
Venida	Delta	12	0	0	0	0	0	0	0	0
Deluz P.T.	Deluz	12	2.84	2.84	2.84	2.84	3.26	3.26	3.26	2.79
Oak Grove	Demaree	12	0	0	0	0	0	0	0	0
Oxnard	Dempsey	4.16	0	0	0	0	1.21	0.64	0.43	0.36
Lark Ellen	Denise	12	2.22	0	0	0	3.44	3.44	3.44	3.44
Howard	Denker	4.16	0	0	0	0	0.99	0.58	0.45	0.38
Little Rock	Dennis	12	5.19	5.19	5.19	5.19	3.49	3.4	3.4	2.73
Timoteo	Dental	12	2.69	2.69	2.69	2.69	2.68	2.68	2.25	1.9
Cameron	Denver	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
La Habra	Deodara	12	0	0	0	0	3.49	3.49	3.49	3.49
Colton	Derby	12	6.68	6.68	3.02	3.02	3.46	3.46	3.14	2.61
Signal Hill	Derrick	4.16	0.37	0.37	0.37	0.37	0.66	0.66	0.66	0.56
Lancaster	Desert	4.16	1.01	0	0	0	0.62	0	0	0
Eagle Mountain	DesertCenter	12	0	0	0	0	0	0	0	0
Garnet	DesertCrest	12	10	0	0	0	3.49	0	0	0
Pico	Desmond	12	8.32	0	0	0	3.49	0	0	0
Cady	Desolate	12	0	0	0	0	0	0	0	0
Narod	Dessau	12	1.93	1.93	1.93	1.93	3.41	3.41	3.41	3.35
Norco	Detroit	4.16	0.92	0	0	0	0.77	0	0	0
Gallatin	Deuce	12	5.01	5.01	5.01	5.01	3.45	3.45	3.45	3.45
Arroyo	DevilsGate	16	2.49	2.49	2.49	2.49	7.58	6.35	5.72	5.31
Thousand Oaks	Devine	16	2.11	2.11	2.11	2.11	7.44	6.27	5.57	5.17
Bovine	Devon	12	3.46	3.46	3.46	3.46	2.81	2.81	2.81	2.81
Newhall	Dewitt	16	3.95	3.95	3.95	3.95	8	6.07	5.45	4.99
Ganesha	Diabar	12	0	0	0	0	3.49	0	0	0
San Miguel	Diablo	16	0.34	0.34	0.34	0.34	5.98	4.93	4.42	4.1
Liberty	Diamante	12	0	0	0	0	0	0	0	0
Arcadia	Diamond	4.16	0	0	0	0	1.23	0.74	0.59	0.49
North Oaks	Diamondback	16	1.97	1.97	1.97	1.97	7.57	5.7	5.27	4.78
Marion	Diana	12	1.67	1.67	1.67	1.67	3.44	3.44	3.44	3.44
Moraga	Diaz	12	0.34	0.34	0.34	0.34	3.11	3.11	2.87	2.4
Phelan	Dice	33	8.38	0	0	0	27	24.6	18.4	13.92
Randolph	Dickerson	16	0.22	0	0	0	7.52	0	0	0
Industry	Die	12	2.37	2.37	2.37	2.37	3.33	3.33	3.02	2.48
Randall	Digby	12	0	0	0	0	2.86	2.86	2.83	2.39
Moreno	Dill	12	0.71	0.71	0.71	0.71	3.36	3.36	3.24	2.68
Garnet	Dillon	12	3.46	0	0	0	3.48	0	0	0
Santiago	Dime	12	0	0	0	0	2.4	2.4	2.12	1.79
Railroad	Diner	12	0	0	0	0	3.3	3.3	3.3	3.3
Bolsa	Dingy	12	0	0	0	0	3.41	3.41	3.41	3.41
Dinkey Creek P.T.	DinkeyCreek	4.16	0	0	0	0	0	0	0	0
Chase	Diplomat	12	2.61	2.61	2.61	2.61	3.35	3.35	2.95	2.28
Goldtown	Discovery	12	0.24	0.24	0.24	0.24	0	0	0	0
Gonzales	Ditch	16	0	0	0	0	3.71	3.11	2.8	2.57
Belvedere	Ditman	4.16	0	0	0	0	1.28	0.84	0.65	0.55
La Habra	Ditwood	12	7.26	0	0	0	3.49	0	0	0
Rosamond	Division	12	1.09	0	0	0	2.94	2.94	2.75	2.32
Gilbert	Divot	12	2.88	2.88	2.88	2.88	3.13	3.13	3.13	2.87
Villa Park	Dixie	12	0	0	0	0	2.69	2.69	2.69	2.55
Declez	Dixon	12	0	0	0	0	3.31	3.31	3.23	2.71
San Antonio	Doane	12	1.47	1.47	1.47	1.47	2.98	2.98	2.98	2.98
San Gabriel	Dobbins	4.16	0	0	0	0	1.12	0.56	0.56	0.47
Moulton	Dober	12	0	0	0	0	3.35	3.35	3.35	3.35
Cottonwood	Doble	33	13.37	13.37	8.38	8.38	27	17.64	13.43	9.77
Timoteo	Doctors	12	0.29	0.29	0.29	0.29	3.34	3.34	3.34	2.85
Cedarwood	Doctrine	4.16	1.01	0	0	0	0.62	0	0	0
Laguna Bell	Dodge	16	3.41	3.41	3.41	3.41	6.97	5.8	5.21	4.83
La Mirada	Doe	12	0.73	0.73	0.73	0.73	3.36	3.36	3.36	2.98
Santa Fe Springs	Doerner	12	2.08	2.08	2.08	2.08	3.47	3.47	3.47	3.47
Calcity 'B'	Dogbane	12	0	0	0	0	0	0	0	0
Torrance	Dogwood	16	1.04	1.04	1.04	1.04	8.2	6.6	5.95	5.52
Pioneer	Dohn	4.16	0.26	0.26	0.26	0.26	1.28	0.91	0.54	0.46
Santa Fe Springs	Dolan	12	3.86	3.86	3.86	3.02	3.49	3.49	3.49	3.49
Alhambra	Dolgeville	4.16	0.62	0	0	0	0.68	0	0	0
Oldfield	Dollar	4.16	0	0	0	0	0.92	0.57	0.43	0.36
Dolores P.T.	Dolores	4.16	0.06	0	0	0	1.06	0	0	0
Dolphin P.T.	Dolphin	4.16	0.67	0	0	0	0.8	0	0	0
Domeland P.T.	Domeland	12	0	0	0	0	0	0	0	0
Colton	Domic	12	2.24	2.24	2.24	2.24	3.39	3.39	2.71	2.3
La Fresa	Dominguez	16	2.11	2.11	2.11	2.11	7.69	6.38	5.8	5.35
Victorville	Don	4.16	1.01	0	0	0	1.2	0	0	0
Stewart	Donald	12	0	0	0	0	2.83	2.83	2.83	2.83
Savage	Donert	12	2.79	2.79	2.79	2.79	3.21	3.21	3.21	3.1
Somis	Donlon	16	3.97	3.97	3.94	3.94	5.41	4.46	3.95	3.67
Carson	Donna	16	10.3	0	0	0	9.92	7.87	6.88	6.33
Ivyglen	Donner	12	0	0	0	0	3.35	3.35	3.07	2.6
Cucamonga	Donohue	12	0.09	0.09	0.09	0.09	3.21	3.21	3.21	3.21
Del Rosa	Dooley	12	0.35	0.35	0.35	0.35	3.36	3.36	3.36	3.03
MacArthur	Doolittle	12	1.04	1.04	1.04	1.04	3.16	2.75	2.18	1.84

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Earlimart	Doran	12	0	0	0	0	0	0	0	0
Villa Park	Dorchester	12	3.02	3.02	3.02	3.02	3.48	3.48	3.48	3.48
La Veta	Doris	12	3.02	0	0	0	3.46	0	0	0
Elsinore	Dorman	12	2.01	2.01	2.01	2.01	3.33	3.33	3.33	2.93
Eric	Dornes	12	0.05	0.05	0.05	0.05	3.45	3.45	3.45	3.45
Skylark	Dorof	12	0	0	0	0	3.05	3.05	3.05	2.63
Alder	Dorsey	12	0	0	0	0	0.88	0.88	0.85	0.71
Daisy	Dot	4.16	0.66	0	0	0	0.73	0	0	0
Sullivan	Dover	4.16	0	0	0	0	1.25	0.7	0.54	0.46
Windsor Hills	Dowell	4.16	0.95	0	0	0	0.54	0	0	0
Oldfield	Doyle	4.16	0	0	0	0	1.24	0.77	0.65	0.51
Repetto	Dozier	16	3.97	0	0	0	7.02	0	0	0
Santiago	Drachma	12	0	0	0	0	3.08	3.08	3.08	3.08
Porterville	Drag	12	0	0	0	0	0	0	0	0
San Bernardino	Dragon	12	0.96	0.96	0.96	0.96	2.91	2.91	2.91	2.91
Pixley	Drake	12	0	0	0	0	0	0	0	0
Milliken	Drambuie	12	0.27	0.27	0.27	0.27	2.97	2.97	2.97	2.88
Dike	Dredge	12	2.47	2.47	2.47	2.47	3.49	3.49	2.96	2.49
Homart	Dressen	12	3.02	3.02	3.02	3.02	1.49	1.49	1.49	1.49
Bryan	Dreyer	12	0	0	0	0	2.52	2.52	2.28	1.93
Neptune	Drift	12	3.02	3.02	3.02	3.02	3.39	3.39	3.39	3.39
Wave	Driftwood	12	0.34	0.34	0.34	0.34	3.15	3.15	3.15	3.15
Bowl	Drill	4.16	1.08	0	0	0	0.67	0	0	0
Olinda	Driller	12	1.92	1.92	1.92	1.92	3.26	3.26	3.26	2.92
San Marcos	Driskill	16	2.44	2.44	2.44	2.44	6.13	5.11	4.61	4.28
Inyokern	DriveInn	12	0	0	0	0	0	0	0	0
Delano	Driver	12	0	0	0	0	0	0	0	0
Shuttle	Droid	12	1.62	1.62	1.62	1.62	2.52	2.52	2.52	2.02
Genamic	Drone	12	1.15	1.15	1.15	1.15	2.96	2.9	2.29	1.94
Telegraph	Drum	12	4.45	4.45	4.45	3.02	3.41	3.41	3.41	3.41
Saugus	DryCanyon	16	0	0	0	0	9.03	7.49	6.66	6.17
Santiago	Ducat	12	0	0	0	0	0	0	0	0
Terra Bella	Ducor	12	0	0	0	0	0	0	0	0
Maxwell	Duda	12	0	0	0	0	3.24	3.24	3.24	2.84
San Marcos	Duffer	16	0.93	0.93	0.93	0.93	6	5	4.51	4.19
Duhon P.T.	Duhon	4.16	0.99	0	0	0	1.24	0	0	0
Maraschino	Duke	12	1.56	1.56	1.56	1.56	2.01	2.01	1.89	1.56
Cardiff	Dumas	12	3.79	3.79	3.02	3.02	3.04	3.04	3.04	2.97
Somerset	Dunbar	4.16	0	0	0	0	1.21	0.83	0.62	0.52
South Gate	Duncan	4.16	0	0	0	0	1.24	0.79	0.62	0.52
Wabash	Dundas	16	7.93	0	0	0	7.02	0	0	0
Venida	Dungan	12	0	0	0	0	0	0	0	0
Puente	Dunkirk	12	0.43	0.43	0.43	0.43	3.44	3.44	3.44	3.13
Homart	Dunlap	12	3.02	3.02	3.02	3.02	2.9	2.9	2.9	2.43
Randall	Dunning	12	0.32	0.32	0.32	0.32	2.92	2.92	2.59	2.2
Woodruff	Dunrobin	4.16	0	0	0	0	0.68	0	0	0
Neenach	Duntley	12	3.34	3.34	3.34	3.34	3.42	2.57	2.06	1.72
Cabrillo	Dupont	12	0	0	0	0	3.42	3.42	3.42	3.42
Culver	Durango	4.16	0.12	0.12	0.12	0.12	1.2	0.78	0.57	0.48
Bartolo	Durfee	4.16	0.17	0.17	0.17	0.17	1.24	0.76	0.6	0.5
Bovine	Durham	12	0	0	0	0	3.33	3.33	3.33	3.33
Timoteo	Durox	12	1.64	1.64	1.64	1.64	0	0	0	0
Layfair	Durward	12	1.91	1.91	1.91	1.91	3.43	3.43	3.43	2.99
Cherry	Dusk	12	3.02	0	0	0	3.49	0	0	0
Rio Hondo	Dusty	16	8.11	8.11	4.96	4.96	9.42	7.57	6.61	6.14
Quartz Hill	Dweezil	12	4.1	4.1	4.1	4.1	2.47	2.28	2.28	1.89
Genamic	Dynamics	12	2.28	2.28	2.28	2.28	3.49	3.49	3.49	2.98
Lundy	Dynamo	16	0	0	0	0	0	0	0	0
Dysart P.T.	Dysart	12	0.26	0.26	0.26	0	3.45	3.45	3.45	3.45
Kramer	Dyson	33	0	0	0	0	0	0	0	0
Stoddard	EStreet	4.16	1.95	0	0	0	1	0	0	0
Talbert	Eagle	12	0.75	0	0	0	3.4	0	0	0
Eagle Crest P.T.	EagleCrest	12	0	0	0	0	3.49	3.49	3.49	3.49
Victor	EagleRanch	12	2.79	2.79	2.79	2.79	3.04	3.04	3.04	2.63
Bowl	Earl	4.16	0.88	0.88	0.88	0.88	1.29	0.76	0.76	0.59
Cucamonga	Earnhardt	12	1.27	1.27	1.27	1.27	0.69	0.67	0.56	0.45
Mt. Pass	Earth	12	0	0	0	0	0	0	0	0
Delano	EastCity	4.16	0	0	0	0	0	0	0	0
Peyton	EastEnd	12	0	0	0	0	2.43	2.43	2.43	2.43
San Vicente	EastMontana	4.16	0	0	0	0	0.87	0.54	0.42	0.35
Nelson	Easter	12	0.17	0.17	0.17	0.17	0.21	0.17	0.13	0.11
Stirrup	Eastfield	4.16	0	0	0	0	0.72	0.48	0.38	0.32
Bandini	Eastland	16	8.4	3.97	3.97	3.97	9.64	7.37	6.45	5.97
Bicknell	Eastmont	4.16	0	0	0	0	0.77	0	0	0
Wilsona	Eastwind	12	2.37	2.37	2.37	2.37	1.46	1.46	1.43	1.13
Davidson City	Easy	4.16	0.16	0	0	0	0.64	0	0	0
Pico	Ebbtide	12	0	0	0	0	3.49	0	0	0
Lakewood	Ebell	4.16	0	0	0	0	1.14	0.82	0.63	0.53
Fogarty	Ebert	12	0	0	0	0	3.49	3.49	3.46	2.82
Torrance	Ebony	16	3.97	0	0	0	13	0	0	0

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Del Rosa	Echo	12	3.02	3.02	3.02	3.02	3.2	3.2	3.2	3.1
Estrella	Eclipse	12	0	0	0	0	3.41	3.41	3.41	3.41
Ely	Ecuador	12	2.71	2.71	2.71	2.71	3.31	3.31	3.31	3.31
Tipton	Edendale	12	0	0	0	0	0	0	0	0
Alon	Edgar	12	3.02	3.02	3.02	3.02	2.58	2.58	2.58	2.58
Fairfax	Edinburg	16	4.83	4.83	4.83	3.97	10.05	6.87	6.16	5.46
Ivar	Edmond	4.16	0.03	0.03	0.03	0.03	1.17	0.85	0.65	0.55
Vera	Edsel	12	3.02	3.02	3.02	3.02	3.47	3.47	3.47	3.47
Alessandro	Edwin	12	0.9	0.9	0.9	0.9	2.14	2.14	1.96	1.63
Oak Grove	Effie	12	0	0	0	0	0	0	0	0
Beaumont	Egan	4.16	1.73	0	0	0	0.76	0	0	0
Cortez	Egmont	12	1.52	1.52	1.52	1.52	2.53	2.53	2.53	2.23
Ripley	Eighteenth	12	3.02	2.07	2.07	2.07	3.46	3.14	2.47	2.09
Palm Canyon	ElCamino	4.16	0.72	0	0	0	1.05	0	0	0
Garfield	ElCentro	4.16	0.7	0	0	0	0.71	0	0	0
Strathmore	ElMirador	12	0	0	0	0	0	0	0	0
Amador	ElMonte	4.16	0.44	0	0	0	0.64	0	0	0
Redondo	ElPaseo	4.16	0.69	0	0	0	0.87	0.75	0.44	0.37
Oxnard	ElRio	4.16	0	0	0	0	1.03	0.64	0.5	0.42
Irvine	ElToro	12	0	0	0	0	2.56	2.56	2.56	2.18
Irvine	Elden	12	1.79	1.79	1.79	1.79	3.37	3.37	3.06	2.56
Rialto	Elder	12	2.61	2.61	2.61	2.61	3.45	3.45	3.45	3.45
Los Cerritos	Eldridge	4.16	0	0	0	0	0.95	0.61	0.45	0.38
Lark Ellen	Eleanor	12	2.35	2.35	2.35	2.35	3.09	3.09	3.09	3.09
Lockheed	Electra	16	1.05	1.05	1.05	1.05	5.07	4.26	3.83	3.54
Culver	Electric	16	3.97	0	0	0	7.81	0	0	0
Elementary P.T.	Elementary	4.16	0.67	0	0	0	1.29	0	0	0
Lampson	Elephant	12	0	0	0	0	2.6	2.6	2.6	2.6
Beverly	Elevado	4.16	0.17	0	0	0	0.67	0	0	0
Granada	Elgin	4.16	0	0	0	0	0.62	0	0	0
Blythe City	Elhers	4.8	0	0	0	0	1.03	0.67	0.53	0.44
Octol	Elk	12	0	0	0	0	0	0	0	0
Belmont	Elko	4.16	0.94	0	0	0	0.79	0	0	0
Lucas	Elkport	12	1.75	1.75	1.75	1.75	3.14	3.14	3.14	2.93
Rolling Hills	Ellenwood	16	4.29	4.29	4.29	3.97	8.87	7.26	6.57	6.03
Delano	Ellington	12	0	0	0	0	0	0	0	0
Arro	Elliot	4.16	0.13	0	0	0	0.8	0	0	0
Lancaster	Elm	4.16	1.01	0	0	0	0.81	0	0	0
Eaton	Elmer	16	2.62	2.62	2.62	2.62	7.15	5.98	5.39	5.01
Costa Mesa	Elmira	4.16	0.45	0.45	0.45	0.45	0.89	0.56	0.45	0.37
Browning	Elmo	12	0	0	0	0	0	0	0	0
Oak Grove	Elowin	12	0	0	0	0	0	0	0	0
Cabrillo	Elpac	12	0	0	0	0	3.49	3.49	3.49	3.49
Soquel	Elprado	12	1.31	1.31	1.31	1.31	3.17	3.17	3.17	3.17
La Fresa	Elroy	16	2.24	2.24	2.24	2.24	5.95	4.65	4.19	3.89
Boxwood	Elster	12	0	0	0	0	0	0	0	0
Alessandro	Elsworth	12	0	0	0	0	3.27	3.27	2.69	2.28
Emigrant P.T.	Emigrant	12	0	0	0	0	3.49	0	0	0
Stewart	Emory	12	1.29	1.29	1.29	1.29	3.49	3.49	3.49	3.49
San Marcos	Empire	16	2.97	2.97	2.97	2.97	7.43	6.24	5.62	5.22
Ontario	Emporia	4.16	0.06	0.06	0.06	0.06	1.27	0.87	0.7	0.58
O'neill	Empresa	12	0	0	0	0	3.27	3.27	3.27	2.81
Fruitland	Emsco	16	3.97	3.97	3.97	3.97	8.72	7.28	6.46	5.99
Isla Vista	Encanto	16	3.22	3.22	3.22	3.22	6.91	5.75	5.22	4.82
Royal	Enchanted	16	2.72	2.72	2.72	2.72	6.61	5.05	4.52	4.17
Ravendale	Endicott	4.16	0	0	0	0	1.16	0.72	0.53	0.45
Shuttle	Endor	12	5.05	3.02	3.02	3.02	3.23	3.23	3.23	3.23
Chatsworth	Energy	16	3.97	3.97	3.94	3.94	0	0	0	0
Railroad	Engine	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Inglewood	England	4.16	0	0	0	0	0.8	0.8	0.62	0.52
Sullivan	English	12	2.61	2.61	2.61	2.61	3.41	3.41	3.41	2.94
Dalton	Enid	12	4.49	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Amador	Enloe	16	2.62	2.62	2.62	2.62	7.6	6.34	5.71	5.31
Huntington Park	Ensign	4.16	0.67	0	0	0	0.64	0	0	0
Levy	Enterprise	16	2.09	2.09	2.09	2.09	4.93	4.06	3.67	3.41
Thornhill	Entrada	12	0	0	0	0	3.39	3.39	3.39	3.39
Carson	Epsilon	16	4.57	4.57	3.97	3.97	11.55	7.25	6.48	6.01
Sun City	Equinox	12	3.46	3.46	3.46	3.02	3.34	2.95	2.33	1.97
Bowl	Erie	4.16	0	0	0	0	1.26	0.71	0.71	0.57
Mayberry	Erin	12	0.39	0.39	0.39	0.39	3.38	3.38	3.38	2.98
Royal	Erringer	16	0	0	0	0	8.06	6.02	5.42	5.02
Isabella	Erskine	12	0	0	0	0	0	0	0	0
Escala P.T.	Escala	12	2.09	0	0	0	3.49	0	0	0
La Mirada	Escalona	12	2.43	0	0	0	3.36	3.36	3.36	3.36
Narrows	Escamilla	12	0	0	0	0	3.47	3.47	3.47	2.96
Escondido P.T.	Escondido	12	1	0	0	0	3.49	0	0	0
Coffee	Espresso	12	0	0	0	0	1.48	1.46	1.14	0.97
Vera	Essex	12	0.66	0.66	0.66	0.66	3.45	3.45	3.45	3.45
Somis	Estaban	16	3.37	3.37	3.37	3.37	5.39	4.53	4.08	3.79
Repetto	Estates	4.16	0.63	0	0	0	1.28	0.53	0.53	0.53

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Bowl	Esther	4.16	0.78	0	0	0	0.82	0	0	0
Valley	Ethanac	12	1.45	1.45	1.45	1.45	2.4	2.4	1.95	1.66
Levy	Etting	16	6.54	6.54	0	0	10.02	8.32	7.37	6.75
Peyton	Eucalyptus	12	3.46	3	3	3	3.11	3.11	2.64	2.24
Rio Hondo	Euphrates	12	1.7	1.7	1.7	1.7	2.6	2.6	2.36	2
Santiago	Euro	12	0	0	0	0	3.14	3.04	2.44	2.05
Rolling Hills	Evans	16	0	0	0	0	8.68	6.97	6.25	5.77
Mira Loma	Everest	12	0.7	0.7	0.7	0.7	3.16	3.16	3.16	2.96
Moorpark	Everett	16	3.92	3.92	3.92	3.92	8.81	7.25	6.5	6.04
South Gate	Evergreen	4.16	0	0	0	0	1.26	0.87	0.69	0.58
Camarillo	Evita	16	1.37	1.37	1.37	1.37	7.05	5.97	5.39	4.97
Pioneer	Excelsior	4.16	0.43	0.43	0.43	0.43	1.27	0.62	0.62	0.52
Beverly	Executive	16	1.28	1.28	1.28	1.28	9.99	7.99	6.97	6.37
Amador	Exline	16	1.18	1.18	1.18	1.18	8.26	6.84	6.17	5.73
Gisler	Explorer	12	2.19	2.19	2.19	2.19	3.49	3.49	3.49	3.3
Stoddard	Expo	4.16	0.65	0.65	0.65	0.65	1.14	0.88	0.6	0.51
Barstow	Express	33	0	0	0	0	0	0	0	0
Firehouse	Extinguisher	12	1.68	1.68	1.68	1.68	2.49	2.49	2.49	2.49
Bridge	Ezra	4.16	0	0	0	0	1.2	0.53	0.53	0.45
Stadler	Facemask	12	0.67	0.67	0.67	0.67	2.05	2.05	2.05	1.88
Yukon	Factor	16	4.96	0	0	0	8.16	6.83	6.15	5.69
Walnut	Factory	12	0	0	0	0	3.49	0	0	0
Lucas	Faculty	4.16	0.07	0.07	0.07	0.07	1.01	0.62	0.53	0.41
Greening	Fagan	12	1.57	1.57	1.57	1.57	3.19	3.19	3.19	3.19
Hemet	Fair	4.8	0	0	0	0	1.29	0	0	0
Santa Barbara	FairAcres	4.16	1.01	1.01	1.01	1.01	1.17	0.98	0.57	0.44
Yukon	Fairbanks	4.16	0	0	0	0	1.25	0.9	0.49	0.41
Inglewood	Fairhaven	16	1.01	1.01	1.01	1.01	7.5	6.35	5.6	5.21
Lindsay	Fairlawn	4.16	0	0	0	0	0	0	0	0
Sunnyside	Fairman	12	1.03	1.03	1.03	1.03	3.46	3.46	3.46	3.46
Del Sur	Fairmont	12	4.45	3.02	3.02	3.02	2.11	1.58	1.18	0.98
Layfair	Fairplex	12	0	0	0	0	3.49	3.49	3.49	2.89
Villa Park	Fairway	12	0.26	0.26	0.26	0.26	3.04	3.04	3.04	2.86
Bixby	Falcon	4.16	0.37	0	0	0	1.29	0	0	0
Ontario	Fallis	4.16	0.33	0.33	0	0	1.29	0.86	0.7	0.51
Eric	Fallon	12	2.12	2.12	2.12	2.12	3.46	3.46	3.46	3.46
Calectric	Famous	33	0	0	0	0	27	27	27	27
Padua	Fano	12	2.83	2.83	2.83	2.83	2.69	2.69	2.69	2.4
Tahiti	Fantail	16	2.09	2.09	2.09	2.09	7.8	6.94	5.48	5.48
Alessandro	Fantastico	12	0.66	0.66	0.66	0.66	3.23	3.23	3.23	2.79
Clark	Fanwood	4.16	0	0	0	0	0.85	0.55	0.44	0.37
Crown	Farallon	12	0	0	0	0	3.47	3.47	3.47	3.47
Hesperia	Fargo	12	1.25	1.25	1.25	1.25	2.11	2.11	1.93	1.63
Newcomb	Farmington	12	4.68	3.02	3.02	3.02	2.9	2.78	2.22	1.85
Oasis	Farms	12	0	0	0	0	2.36	2.36	2.32	1.96
Johanna	Faro	12	3.02	0	0	0	3.49	0	0	0
Santiago	Farthing	12	4.58	3.02	3.02	3.02	2.79	2.79	2.79	2.61
Pico	Fashion	12	3.02	0	0	0	3.49	0	0	0
Clark	Faust	4.16	0.65	0.65	0.65	0.65	1.06	0.58	0.58	0.48
Weldon	Faye	12	0	0	0	0	0	0	0	0
Sawtelle	Federal	16	7.37	0	0	0	10.86	8.15	7.45	6.75
Wimbledon	Federer	12	0	0	0	0	3.32	3.32	2.86	2.43
Cypress	Fela	12	0	0	0	0	3.1	0	0	0
Crest	Feldspar	16	3.97	3.97	3.97	3.97	5.82	4.89	4.38	4.07
Los Cerritos	Felix	12	3.02	0	0	0	3.43	0	0	0
Hamilton	Feller	12	7.08	7.08	7.08	3.02	3.42	3.42	3.42	3.42
Playa	Fellowship	4.16	0.91	0	0	0	0.58	0	0	0
Montebello	Ferguson	4.16	0	0	0	0	1.28	0.67	0.67	0.57
Woodruff	Ferina	4.16	0	0	0	0	1.25	0.83	0.51	0.43
Idyllwild	Fern	2.4	0.58	0	0	0	0.67	0	0	0
Ganesha	Fernstrom	12	0.15	0.15	0.15	0.15	3.27	3.27	3.11	2.51
Archline	Feron	12	0.92	0.92	0.92	0.92	2.6	2.6	2.6	2.6
Padua	Ferrara	12	0.25	0.25	0.25	0.25	2.65	1.81	1.41	1.19
Ellis	Ferree	12	3.21	3.21	3.21	3.02	3.4	3.4	3.4	3.26
Amalia	Fetterly	4.16	0.98	0	0	0	0.65	0	0	0
Farrell	Fey	12	0.63	0.63	0.63	0.63	2.63	2.63	2.63	2.63
Neptune	Fiat	4.16	1.01	0	0	0	0.64	0	0	0
Hedda	Fidler	4.16	0	0	0	0	1.19	0.79	0.47	0.39
Walnut	Fieldgate	12	0	0	0	0	3.09	3.09	3.06	2.57
Etiwanda	Fields	12	0	0	0	0	3.48	3.48	3.48	3.36
Anita	Fiesta	4.16	0	0	0	0	1.13	0.53	0.53	0.45
Colonia	FifthSt.	16	0.05	0.05	0.05	0.05	5.45	4.56	4.13	3.81
Bradbury	Fig	16	3.04	3.04	3.04	3.04	7.66	6.32	5.73	5.29
Santa Barbara	Figueroa	4.16	1.2	1.01	0	0	1.27	0.88	0.62	0.52
Bryan	Fiji	12	0	0	0	0	3.49	3.49	3.49	3.49
Chestnut	Filbert	12	3.02	0	0	0	3.49	0	0	0
Inglewood	Filly	16	3.94	3.94	3.94	3.94	9.3	6.87	6.18	5.71
Placentia	Finals	12	0	0	0	0	3.47	3.47	3.47	3.47
Narod	Finch	12	0.7	0.7	0.7	0.7	3.22	3.22	3.22	3.22
Vail	Findley	16	0.21	0.21	0.21	0.21	7.73	6.44	5.8	5.39

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Cabazon	Fingal	12	2.74	2.74	2.74	2.74	3.37	2.84	2.17	1.83
Trophy	Finishline	12	0	0	0	0	3.25	3.25	3.2	2.7
Lynwood	Fir	4.16	0.67	0.67	0.67	0.67	1.24	0.82	0.67	0.55
Torrance	Firethorn	16	0	0	0	0	7.2	5.83	5.31	4.89
Viejo	Firme	12	3	3	3	3	3.01	3.01	3.01	2.53
La Fresa	Firmona	16	3.95	3.95	3.95	3.95	8.43	7.06	6.33	5.89
Los Cerritos	Firth	12	3.02	0	0	0	3.49	0	0	0
Cucamonga	Fittipaldi	12	3.02	3.02	3.02	3.02	3.42	3.42	3.42	3.42
Chiquita	Fizz	12	0.51	0.51	0.51	0.51	3.36	3.36	3.06	2.56
Rubidoux	Flabob	12	3.02	3.02	3.02	3.02	3.29	3.29	3.29	3.29
Sunnyside	Flagg	12	2.83	2.83	2.83	2.83	3.12	3.12	3.12	3.12
Elsinore	Flagstaff	12	0	0	0	0	2.56	2.56	2.56	1.99
Flagstone P.T.	Flagstone	4.16	0.36	0	0	0	1.29	0	0	0
Maxwell	Flake	12	0.2	0.2	0.2	0.2	3.14	3.14	3.14	3.14
Firehouse	Flame	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
La Canada	Flanders	4.16	0.2	0.2	0.2	0.2	0.72	0.48	0.38	0.32
Sun City	Flare	12	3.18	3.18	3.18	3.18	2.96	2.96	2.96	2.96
Lighthipe	Flask	12	2.52	2.52	2.52	2.52	3.45	3.45	3.45	3.45
Bloomington	Flatcar	12	0	0	0	0	2.34	2.34	2.06	1.75
Valley	Flats	12	1.21	1.21	1.21	1.21	3.08	2.8	2.21	1.87
West Riverside	Fleetwood	12	1.27	1.27	1.27	1.27	3.48	3.48	3.48	3.38
Imperial	Fleming	12	1.94	1.94	1.94	1.94	3.49	3.49	3.49	3.49
Eisenhower	Flight	12	2.33	2.33	2.33	2.33	3.27	3.27	3.27	3.27
Trask	Flint	12	0.76	0.76	0.76	0.76	3.06	3.06	3.06	2.64
La Canada	Flintridge	4.16	0	0	0	0	0.97	0.49	0.37	0.3
Seabright	Float	12	2.8	2.8	2.8	2.8	3.49	3.49	3.49	3.49
Aqueduct	Floodgate	12	0.2	0.2	0.2	0.2	1.82	1.57	1.24	1.06
Repetto	Floral	16	1.43	1.43	1.43	1.43	8.16	6.85	6.19	5.74
Cudahy	Florence	16	0	0	0	0	8.21	6.89	6.26	5.77
Fairview	Flores	12	3.02	0	0	0	3.45	0	0	0
Carolina	Florida	12	0	0	0	0	3.09	3.09	3.09	3.09
Hanford	Florinda	12	0	0	0	0	0	0	0	0
Woodville	Flory	12	0	0	0	0	0	0	0	0
Vail	Flotilla	16	0	0	0	0	8.72	7.29	6.57	6.11
Edinger	Flower	4.16	0.05	0.05	0.05	0.05	1.22	1.03	0.6	0.5
Aqueduct	Flue	12	0.09	0.09	0.09	0.09	0	0	0	0
Niguel	Flute	12	1.29	1.29	1.29	1.29	3.39	3.39	3.39	3.39
Havilah	FlyingD	12	1.53	1.53	1.53	1.53	3.44	2.93	2.38	1.97
Camarillo	Flynn	16	0	0	0	0	6.05	5.03	4.53	4.21
Ditmar	Flywheel	16	3.97	0	0	0	7.02	0	0	0
Chiquita	Fogcutter	12	0	0	0	0	3.02	3.02	3.02	2.86
Tulare	Fogg	12	0	0	0	0	0	0	0	0
Bassett	Folger	12	3.02	3.02	3.02	3.02	3.39	3.39	3.39	3.39
La Habra	Fonda	12	1.86	1.86	1.86	1.86	3.46	3.46	3.46	3.46
Calectric	Fonri	33	7.77	7.77	7.77	7.77	27	27	22.89	13.75
Stadler	Football	12	7.93	7.93	7.93	7.93	3.47	3.47	3.47	3.47
Stadium	Foote	12	3.02	3.02	3	3	3.38	3.38	3.38	3.28
San Dimas	Foothill	12	0	0	0	0	3.27	3.27	3.27	3.27
Piute	Forage	12	2.94	2.94	2.94	2.94	0	0	0	0
Live Oak	Forbes	12	1.52	1.52	1.52	1.52	3.22	3.22	3.22	3.22
Rush	Forbid	16	0	0	0	0	7.62	6.36	5.73	5.32
Shuttle	Force	12	1.25	1.25	1.25	1.25	2.31	2.31	2.31	2.31
Dike	Ford	12	3.46	3.46	3.46	3.02	3.49	3.49	3.49	3.24
State Street	Forest	12	3.78	0	0	0	3.49	0	0	0
Santiago	Forint	12	2.09	2.09	2.09	2.09	3.39	3.39	3.39	3.04
Fairfax	Formosa	16	3.97	0	0	0	7.32	0	0	0
Kimball	Fortress	12	0	0	0	0	1.88	1.88	1.7	1.44
Forty Eight St. P.T.	FortyEightSt.	4.16	0.5	0	0	0	1.29	0	0	0
Ventura	Foster	4.16	0.62	0	0	0	0.62	0	0	0
Founders P.T.	Founders	4.16	0.12	0	0	0	1	0	0	0
Fairfax	Fountain	4.16	0.44	0	0	0	0.7	0	0	0
Modoc	Fox	4.16	0.7	0.7	0.7	0.7	0.95	0.63	0.48	0.41
Badillo	Foxdale	4.16	0.3	0	0	0	0.81	0	0	0
Barre	Foxglove	12	0	0	0	0	3.41	3.41	3.39	2.87
Cucamonga	Foyt	12	0	0	0	0	3.46	3.46	3.46	3.46
Porterville	Frame	4.16	0	0	0	0	0	0	0	0
Santiago	Franc	12	0.3	0.3	0.3	0.3	3.29	3.29	3.29	2.91
Colorado	Franklin	16	3.79	0	0	0	7.63	0	0	0
Isla Vista	Fraternity	16	3.97	3.97	3.97	3.97	7.77	6.37	5.72	5.32
Liberty	Freedom	12	0	0	0	0	0	0	0	0
Oldfield	Freeland	4.16	0.97	0	0	0	0.63	0	0	0
Lawndale	Freeman	4.16	0.53	0.53	0.53	0.53	1.24	0.83	0.64	0.54
Declez	Freeway	4.16	1.56	1.56	0	0	0.89	0.89	0.64	0.53
Roadway	Freightliner	12	3.02	3.02	3.02	3.02	2.2	2.2	2.2	1.88
Garfield	Fremont	4.16	0.23	0.23	0.23	0.23	1.25	0.89	0.68	0.56
Santa Fe Springs	Friends	12	1.98	1.98	1.98	1.98	3.23	3.23	3.23	3.09
Doheny	Fringe	4.16	0.3	0.3	0.3	0.3	0.82	0.46	0.36	0.3
Alder	Frisbie	12	2.74	2.74	2.74	2.74	3.21	3.21	3.08	2.56
Tortilla	Frito	33	0	0	0	0	0	0	0	0
Savage	Frontage	12	2.33	2.33	2.33	2.33	3.4	3.4	2.53	2.14

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL® Company

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Redlands	Frost	12	0	0	0	0	3.13	3.13	3.13	3.13
Nelson	Fruitvale	12	0	0	0	0	2.92	2.92	2.92	2.92
Watson	Fry	12	3.78	3.02	3.02	3.02	3.46	3.46	3.46	3.46
Fruitland	Fudge	4.16	1.01	0	0	0	0.7	0	0	0
Nogales	Fuerte	12	0	0	0	0	3.26	3.26	3.26	3.26
Mira Loma	Fujiyama	12	0.02	0.02	0.02	0.02	2.88	2.88	2.88	2.43
Stadler	Fullback	12	0	0	0	0	2.64	2.64	2.64	2.29
Fairfax	Fuller	16	3.27	3.27	3.27	3.27	7.51	6.82	5.66	5.24
Junction	FurnaceCreek	33	3.85	3.85	3.85	3.85	19.96	5.47	3.67	2.87
Viejo	Futuro	12	3.44	0	0	0	3.26	3.26	2.78	2.34
Moorpark	Gabbert	16	3.14	3.14	3.14	3.14	6.75	5.22	4.7	4.36
Movie	Gable	16	4.89	0	0	0	7.19	0	0	0
Gabrielino P.T.	Gabrielino	4.16	0.62	0	0	0	1	0	0	0
Gaffey P.T.	Gaffey1	2.4	0.32	0	0	0	0.68	0	0	0
Ravendale	Gainsborough	16	0	0	0	0	8.98	6.73	6.08	5.64
Latigo	Galahad	16	2.69	2.69	2.69	2.69	4.35	3.65	3.3	3.06
Glen Avon	Galena	12	0	0	0	0	2.8	2.8	2.15	1.83
Galileo P.T.	Galileo	12	0	0	0	0	0	0	0	0
Maywood	Gallion	4.16	1.01	0	0	0	1.29	0	0	0
Palm Village	Gallon	12	0	0	0	0	0	0	0	0
Lucas	Gallup	4.16	0	0	0	0	1.22	0.65	0.65	0.55
Euclid	Galvin	4.16	0	0	0	0	0.59	0	0	0
Alessandro	Gamble	12	0	0	0	0	3.42	3.42	3.42	3.42
Phelan	Gambler	12	3.02	3.02	3.02	3.02	1.42	1.18	0.94	0.8
Telegraph	Gamma	12	2.05	2.05	2.05	2.05	3.34	3.34	3.34	3.34
Farrell	Garbo	12	0	0	0	0	1.21	1.21	1.17	0.99
Auld	Garboni	12	0	0	0	0	2.27	2.27	2.04	1.71
Visalia	Garcia	12	0	0	0	0	0	0	0	0
Eric	Gard	12	2.75	0	0	0	3.44	0	0	0
Amador	Gardea	16	0.72	0.72	0.72	0.72	7.83	6.57	5.96	5.51
Santa Barbara	Garden	4.16	0.76	0	0	0	0.61	0	0	0
Imperial	Gardendale	4.16	0.13	0.13	0.13	0.13	1.06	0.8	0.55	0.46
Pomona	Garey	4.16	0.38	0.38	0.38	0.38	1.23	0.69	0.54	0.46
Clark	Garford	4.16	0.35	0.35	0.35	0.35	0.54	0.54	0.54	0.45
Anita	Garibaldi	16	0	0	0	0	6.92	5.81	5.22	4.85
Cucamonga	Garlits	12	0	0	0	0	3.42	3.42	3.34	2.82
Mt. Vernon	Garner	4.16	0.22	0.22	0	0	1.25	0.83	0.65	0.55
Cypress	Garnsey	12	1.47	1.47	1.47	1.47	3.28	3.28	3.28	3.28
Archibald	Garrett	12	1.84	1.84	1.84	1.84	3.45	3.45	3.45	3.24
Nogales	Gartel	12	0	0	0	0	1.35	1.35	1.35	1.33
Mariposa	Garwood	12	0	0	0	0	0	0	0	0
La Palma	Garza	12	2.06	2.06	2.06	2.06	3.4	3.4	3.4	3.4
Nola	Gasbag	16	3.6	3.6	3.6	3.6	9.67	7.82	7.06	6.56
Gallatin	Gaspar	12	0	0	0	0	3.49	0	0	0
La Habra	Gaston	12	0	0	0	0	3.26	3.26	3.26	3.26
Pearl	Gateway	4.16	0.96	0	0	0	0.88	0	0	0
Walnut	Gatlin	12	0.26	0.26	0.26	0.26	3.41	3.41	3.41	3.3
Vegas	Gaucho	16	4.51	3.97	3.97	3.94	7.63	6.3	5.69	5.28
Newhall	Gavin	16	1.19	1.19	1.19	1.19	6.32	5.26	4.85	4.41
San Antonio	Gaylord	12	0.21	0.21	0.21	0.21	3.45	3.45	3.45	3.45
Lampson	Gazelle	12	0	0	0	0	3.49	3.49	3.49	3.49
Industry	Gear	12	0	0	0	0	3.08	3.08	3.08	3.08
Felton	Gearline	16	3.69	3.69	3.69	3.69	8.72	6.86	6.08	5.64
Hanford	GeeBee	12	0	0	0	0	0	0	0	0
Hamilton	Gehrig	12	0	0	0	0	3.39	3.39	3.39	2.99
Topaz	Gem	4.16	1.01	0	0	0	0.59	0	0	0
La Fresa	GeneralPetroleum	16	3.97	3.97	3.97	3.97	9.72	7.12	6.27	5.82
Wave	Geneva	4.16	0.1	0	0	0	0.7	0	0	0
Santa Monica	Georgian	4.16	0.9	0	0	0	0.62	0	0	0
Lucas	Geraths	12	0	0	0	0	2.79	2.79	2.74	2.32
Rosemead	Gerona	16	0	0	0	0	7.09	5.83	5.33	4.89
Lark Ellen	Gertrude	12	0	0	0	0	2.6	0	0	0
Slater	Giants	12	2.64	2.64	2.64	2.64	3.22	3.22	3.22	3.22
Pomona	Gibbs	4.16	0.07	0.07	0.07	0.07	0.81	0.81	0.57	0.48
Bullis	Gibson	16	3.55	3.55	3.55	3.55	8.86	7.17	6.53	6.01
Visalia	Giddings	12	0	0	0	0	0	0	0	0
Maywood	Gifford	4.16	0.12	0	0	0	1.29	0	0	0
Riverway	Gila	12	0	0	0	0	0	0	0	0
Alder	Gilfillan	12	0.26	0.26	0.26	0.26	3.39	3.39	2.98	2.5
Venida	Gill	12	0	0	0	0	0	0	0	0
Strathmore	Gillette	12	0	0	0	0	0	0	0	0
Santa Susana	Gillibrand	16	0	0	0	0	5.61	4.67	4.26	3.9
La Palma	Gillis	12	3.01	3.01	3.01	3.01	3.36	3.36	3.36	3.36
Ridgeview P.T.	Gilman	12	1.27	1.27	1.27	1.27	3.49	3.49	3.49	3.49
Fairfax	Gilmore	4.16	0.71	0.71	0.71	0.71	1.18	0.76	0.54	0.45
Blythe City	Gin	33	8.86	8.38	0	0	27	25.54	23.62	14.18
Moreno	Ginger	12	3.46	3.02	3.02	3.02	1.14	1.08	0.84	0.71
Nelson	Girard	12	0	0	0	0	3.36	3.36	3.24	2.75
Bridge	Girder	4.16	0	0	0	0	1.22	0.57	0.57	0.49
Channel Island	Gizmo	16	3.76	3.76	3.76	3.76	7.52	6.31	5.69	5.29

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Corona	Glacier	12	0	0	0	0	2.88	2.88	2.72	2.29
Isla Vista	Gladiola	16	6.49	3.97	3.97	3.97	6.89	5.58	5.03	4.67
San Dimas	Gladstone	12	1.27	1.27	1.27	1.27	2.26	2.26	2.26	2.26
Rosemead	Gladys	16	0	0	0	0	6.88	5.71	5.17	4.78
Inglewood	Glasgow	4.16	1.01	1	1	1	0.86	0.55	0.42	0.36
Laguna Bell	Glass	16	3.97	0	0	0	6.97	0	0	0
Santa Susana	Glasscock	16	0	0	0	0	7.07	5.96	5.34	4.94
Repetto	Gleason	16	1.27	1.27	1.27	1.27	7.77	6.41	5.8	5.38
Peyton	GlenRidge	12	0.33	0.33	0.33	0.33	3.45	3.45	3.45	3.45
Longdon	Glencoe	4.16	0.55	0.55	0.55	0.55	1.25	0.83	0.67	0.55
Ramona	Glendon	4.16	0	0	0	0	0.84	0	0	0
La Palma	Glidden	12	4.17	4.17	3	3	3.26	3.26	3.26	3.26
Stetson	Glider	12	2.28	2.28	2.28	2.28	3.39	3.39	3.39	3.29
Colton	GlobeMills	12	0	0	0	0	3.37	3.37	3.23	2.74
Arcadia	Gloria	16	2.94	2.94	2.94	2.94	7.92	6.36	5.64	5.24
Octol	Glover	12	0	0	0	0	0	0	0	0
Cottonwood	Gobar	33	8.38	8.38	8.38	8.38	0	0	0	0
Quartz Hill	Godde	12	1.51	1.51	1.51	1.51	1.97	1.97	1.97	1.97
Newcomb	Goetz	12	3.7	3.7	3.02	3	2.36	2.36	1.91	1.6
Limestone	Gold	12	0	0	0	0	3.34	3.34	3.34	3.34
Highland	Goldbuckle	12	0	0	0	0	3.17	3.17	3.09	2.62
Locust	Golden	4.16	1.21	1.01	1.01	1.01	1.23	0.84	0.67	0.56
Mascot	Goldenbear	12	0	0	0	0	0	0	0	0
Michillinda	Goldenwest	4.16	0.02	0	0	0	0.68	0	0	0
Thousand Oaks	Goldsmith	16	0	0	0	0	5.92	4.88	4.4	4.07
MacArthur	Goldwater	12	2.44	2.44	2.44	2.44	3.18	3.18	2.91	2.47
Culver	Goldwyn	4.16	0.11	0	0	0	0.61	0	0	0
Railroad	Gondola	12	1.24	1.24	1.24	1.24	3.39	3.39	3.39	3.39
Mt. Vernon	Goodner	4.16	0.04	0.04	0.04	0.04	1.29	0.95	0.71	0.58
Wheatland	Gopher	12	0	0	0	0	0	0	0	0
Viejo	Gordo	12	0	0	0	0	3.49	3.49	3.49	3
Rector	Gordon	12	0	0	0	0	0	0	0	0
Arroyo	Gorge	16	2.78	2.78	2.78	2.78	6.85	5.72	5.16	4.8
Victor	Goss	12	1.63	1.63	1.63	1.63	3.12	3.12	3.12	2.86
Floraday	Gotham	4.16	0	0	0	0	1.01	0.58	0.47	0.39
Glen Avon	Gowan	12	0.25	0.25	0.25	0.25	2.14	2.14	1.9	1.59
La Habra	Grace	12	0	0	0	0	3.19	3.19	3.1	2.56
Placentia	Graduate	12	0	0	0	0	3.47	3.47	3.47	3.47
Wimbledon	Graf	12	2.33	2.33	2.33	2.33	2.49	2.49	2.49	2.49
Maxwell	Graham	12	0	0	0	0	3.1	3.1	3.1	2.99
Sepulveda	Grand	4.16	1.01	0	0	0	0.79	0	0	0
Casitas	Grandad	16	2.76	2.76	2.76	2.76	8.17	5.33	4.98	4.44
Concho	Grande	12	0	0	0	0	0	0	0	0
Yukon	Grandview	4.16	0	0	0	0	1.27	0.74	0.55	0.47
Porterville	Granite	12	0	0	0	0	0	0	0	0
El Casco	GrannySmith	12	4.21	4.21	3.02	3.02	0.41	0.33	0.26	0.22
Lucas	Grant	4.16	0	0	0	0	1.25	0.84	0.66	0.55
Fernwood	Grape	16	4.47	3.97	3.94	3.94	8.1	6.81	6.12	5.69
Citrus	Grapefruit	12	1.36	1.36	1.36	1.36	3.4	3.4	3.4	3.4
Limestone	Graphite	12	1.68	1.68	1.68	1.68	3.49	3.49	3.49	3.49
Chiquita	Grasshopper	12	0	0	0	0	3.03	3.03	3.03	2.86
Dalton	Gravel	12	0.61	0.61	0.61	0.61	3.43	3.43	3.43	3.38
Alhambra	Graves	4.16	0.47	0.47	0.47	0.47	0.99	0.77	0.43	0.36
La Fresa	Graveyard	16	6.55	6.55	3.97	3.97	8.05	6.75	6.03	5.59
Anita	Graydon	16	0.34	0.34	0.34	0.34	7.85	6.27	5.65	5.25
Morningside	Grayson	4.16	0	0	0	0	1.27	0.89	0.69	0.59
Walnut	Grazide	12	0.42	0.42	0.42	0.42	3.47	3.47	3.47	3.47
Calcity 'A'	Greasewood	12	0	0	0	0	0	0	0	0
Bliss	Green	12	0	0	0	0	0	0	0	0
Hemet	GreenAcres	12	0.34	0.34	0.34	0.34	3.45	3.45	3.45	3.45
Green Bear P.T.	GreenBear	2.4	0.19	0	0	0	1.14	0	0	0
Canyon	GreenRiver	12	0	0	0	0	3.28	3.28	3.28	2.99
Victorville	GreenTree	12	7.03	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Green Valley P.T.	GreenValley	4.16	0.22	0	0	0	0.78	0	0	0
Slater	Greenbay	12	3.02	3.02	3	3	1.33	1.33	1.33	1.3
Estero	Greenhouse	16	4.96	4.96	4.96	4.96	0	0	0	0
Montebello	Greenwood	4.16	0	0	0	0	1.04	0.72	0.55	0.46
Yermo	Greer	12	0	0	0	0	0	0	0	0
Anita	Gregg	16	1.33	1.33	1.33	1.33	8.31	6.95	6.24	5.79
Downs	Gregory	12	0	0	0	0	0	0	0	0
Eisenhower	Grenade	12	0.16	0.16	0.16	0.16	2.53	2.53	2.53	2.53
Marion	Greta	12	1.92	1.92	1.92	1.92	3.45	3.45	3.45	3.45
Garfield	Grevelia	4.16	0.33	0.33	0.33	0.33	1.25	0.89	0.75	0.57
Archline	Grey	12	1.48	1.48	1.48	0	3.25	3.25	3.25	3.25
Moulton	Greyhound	12	1.45	1.45	1.45	1.45	3.4	3.4	3.4	3.09
Stadler	Gridiron	12	0	0	0	0	2.84	2.84	2.84	2.84
Eric	Gridley	12	3.13	3.02	3.02	3.02	3.14	3.14	3.14	3.14
Chase	Griffin	12	0	0	0	0	2.95	2.95	2.95	2.95
Archline	Grilley	12	0	0	0	0	1.46	1.46	1.22	1.01
Grimshaw P.T.	Grimshaw	2.4	0	0	0	0	1.01	0	0	0

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Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Industry	Grinder	12	0.67	0.67	0.67	0.67	3.17	3.17	3.17	3.17
San Miguel	Gringo	16	1.66	1.66	1.66	1.66	7.21	6.12	5.47	5.07
El Nido	Grizzley	16	2.13	2.13	2.13	2.13	8.29	6.96	6.28	5.83
Camp 10	Grouse	7	0	0	0	0	0	0	0	0
Rosamond	Grubstake	12	6.47	3.02	3.02	3.02	0	0	0	0
Bayside	Grunion	12	3.02	3.02	3.02	3.02	3.03	3.03	3.03	2.61
Skylark	Gruwell	12	0	0	0	0	2.91	2.91	2.44	2.04
Trask	Guam	12	0.3	0.3	0.3	0.3	3.38	3.38	3.38	3.38
Stadler	Guard	12	0	0	0	0	3.38	3.38	3.38	2.99
Upland	Guasti	12	0	0	0	0	3.45	3.45	3.45	3.45
Oxnard	Guava	4.16	0.33	0.33	0.33	0.33	1.19	0.49	0.49	0.49
Tulare	Guernsey	12	0	0	0	0	0	0	0	0
Ramona	Guest	4.16	0	0	0	0	1.24	0.74	0.58	0.49
Skylark	Guffy	12	1.59	1.59	1.59	1.59	3.21	3.21	3.21	2.89
Genamic	Guidance	12	2.07	2.07	2.07	2.07	2.39	2.39	2.39	2.29
Santiago	Guilder	12	2	2	2	2	3.31	3.26	2.57	2.18
Jefferson	Guinness	12	0	0	0	0	3.04	3.04	2.96	2.42
Westgate	Guirado	4.16	0.11	0	0	0	0.65	0	0	0
Elizabeth Lake	Guitar	16	2.75	2.75	2.75	2.75	0	0	0	0
Neptune	Gulf	4.16	0.93	0.93	0.93	0.93	1.14	0.53	0.53	0.45
June Lake	GullLake	12	0	0	0	0	0	0	0	0
Parkwood	Gum	12	0	0	0	0	3.43	3.43	3.43	3.25
Signal Hill	Gundry	4.16	0	0	0	0	0.79	0.79	0.61	0.51
Bullis	Gunlock	4.16	0.57	0.57	0.57	0.57	1.18	0.85	0.59	0.5
Gunsite P.T.	Gunsite	2.4	0.15	0	0	0	1.29	0.51	0.51	0.51
Crown	Gunther	12	0.72	0.72	0.72	0.72	3.31	3.31	3.3	2.73
Cucamonga	Gurney	12	0	0	0	0	3.31	3.31	3.31	3.31
Olinda	Gusher	12	2.59	2.59	2.59	2.59	2.38	2.38	2.38	2.38
Northwind	Gust	12	3.02	3.02	3.02	3.02	0	0	0	0
Del Rosa	Guthrie	12	0.31	0.31	0.31	0.31	3.34	3.34	3.34	3.14
Santa Barbara	Gutierrez	4.16	0.02	0.02	0.02	0.02	0.49	0.33	0.26	0.22
Canyon	Gypsum	12	3.71	3.71	3.71	3.02	3.27	3.27	3.27	2.96
Potrero	Hacienda	16	0	0	0	0	5.8	4.86	4.42	4.07
Bliss	Hack	12	0	0	0	0	0	0	0	0
Parkwood	Hackberry	12	0	0	0	0	3	3	2.64	2.24
Maxwell	Hackler	12	1.33	1.33	1.33	1.33	3.21	3.21	2.76	2.33
Searles	Hackman	33	0	0	0	0	0	0	0	0
Walnut	Hahn	12	0	0	0	0	3.4	3.4	3.4	3.01
Cortez	Haig	12	0.39	0.39	0.39	0.39	3.31	3.31	3.31	3.31
Ely	Haiti	12	1.26	0	0	0	3.45	0	0	0
Dike	Hale	12	3.02	0	0	0	2.68	0	0	0
Estrella	Haley	12	1.89	1.89	1.89	1.89	3.4	3.4	3.4	3.4
Stadler	Halfback	12	0	0	0	0	3.03	3.03	3.03	2.57
Cypress	Halibut	12	2.09	2.09	2.09	2.09	3.48	3.48	3.48	3.48
Brighton	Halldale	16	4.97	3.97	3.97	3.97	8.19	6.9	6.21	5.76
Inglewood	Hallet	16	7.12	7.12	4.96	3.97	9.73	8.01	7.23	6.71
Shandin	Hallmark	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Villa Park	Hallsworth	12	0.08	0.08	0.08	0.08	3.14	3.14	3.14	2.94
MacArthur	Halsey	12	0	0	0	0	3.48	3.48	3.48	3.48
Los Cerritos	Halter	12	0.64	0.64	0.64	0.64	3.45	3.45	3.45	3.45
Ganesha	Hambone	12	0	0	0	0	3.49	0	0	0
Repetto	Hammell	16	0	0	0	0	7.96	6.76	6.02	5.54
Triton	Hammerhead	12	1.54	1.54	1.54	1.54	3.24	3.24	3.24	3.24
Alessandro	Hammock	33	0	0	0	0	26.48	17.07	11.02	8.16
Thousand Oaks	Hampshire	16	0	0	0	0	5.6	4.72	4.23	3.93
Granada	Hampton	4.16	0.25	0	0	0	0.84	0	0	0
Shuttle	HanSolo	12	0	0	0	0	0	0	0	0
Alon	Hancock	12	5.18	3	3	3	3.43	3.43	3.43	3.06
Railroad	Handcar	12	2.57	2.57	2.57	2.57	3.48	3.48	3.48	3.32
Villa Park	Handy	12	0	0	0	0	2.59	2.59	2.59	2.51
Browning	Hanes	12	0	0	0	0	0	0	0	0
Oasis	Hanger	12	1.37	1.37	1.37	1.37	0	0	0	0
Cucamonga	Hanks	12	2.18	2.18	2.18	2.18	3.49	3.49	3.49	3.22
Neptune	Harbor	4.16	0.52	0.52	0.52	0.52	1.18	0.64	0.51	0.42
Lakewood	Harco	4.16	0.61	0.61	0.61	0.61	0.95	0.43	0.43	0.36
Center	Hardhat	12	5.42	5.42	3.02	3.02	3.47	3.47	3.47	3.47
Linden	Hardwick	4.16	0.41	0	0	0	0.63	0	0	0
Lennox	Hardy	4.16	1.01	0	0	0	0.61	0	0	0
Ditmar	Harkness	4.16	0.66	0.66	0.66	0.66	0.95	0.45	0.45	0.38
Cardiff	HarlemSprings	12	1.4	1.4	1.4	1.4	2.7	2.7	2.44	2.07
Chase	Harlow	12	0	0	0	0	3.19	3.19	3	2.53
Niguel	Harmonica	12	5.47	3.78	3.78	3.78	3.49	3.49	3.49	3.28
Bliss	Harmony	12	0	0	0	0	0	0	0	0
Newcomb	Harnage	12	0	0	0	0	2.45	2.45	1.94	1.64
Costa Mesa	Harper	4.16	0.82	0.82	0.82	0.82	1.21	0.56	0.56	0.48
Doheny	Harratt	4.16	0.1	0.1	0.1	0.1	1.01	0.7	0.47	0.39
Goshen	Harrell	12	0	0	0	0	0	0	0	0
Bunker	Harrier	12	0	0	0	0	3.34	3.34	3.18	2.66
Wabash	Harrison	16	1.49	1.49	1.49	1.49	7.81	6.73	5.92	5.5
Rector	Hart	12	0	0	0	0	0	0	0	0

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Cudahy	Hartle	4.16	1.01	0	0	0	0.61	0	0	0
Pierpont	Hartman	4.16	0.81	0.81	0.81	0.81	1.06	0.55	0.55	0.46
Fullerton	Harvard	4.16	0.11	0.11	0	0	1.14	1	0.52	0.52
Eric	Harvest	12	3.46	3.02	3.02	3.02	3.48	3.48	3.48	3.28
Inyokern Town	HarveyField	4.8	0	0	0	0	0	0	0	0
Tenaja	Harwood	12	0.4	0.4	0.4	0.4	2.75	2.75	2.75	2.75
Arroyo	Haskell	16	0.95	0.95	0.95	0.95	7.1	5.79	5.23	4.83
Mentone	Hass	12	1.48	1.48	1.48	1.48	3.21	3.21	2.85	2.39
Redlands	Hastings	4.16	0.41	0.41	0	0	1.24	0.86	0.67	0.56
Randall	Hasty	12	2.87	2.87	2.87	2.87	3.12	3.12	2.78	2.36
Savage	Hatchery	12	3.52	3.02	3.02	3	3.43	3.43	3.43	3.43
Porterville	Hatfield	12	0	0	0	0	0	0	0	0
Imperial	Hatter	12	2.63	2.63	2.63	2.63	3.1	3.1	3.1	3.1
Hathaway	Havana	12	3.96	3.02	3.02	3.02	3.33	3.33	3.33	3.33
Arcadia	Haven	4.16	0	0	0	0	1.07	0.87	0.59	0.5
La Habra	Havenhurst	12	0	0	0	0	3.46	3.46	3.46	3.43
Cypress	Hawaiian	4.16	0	0	0	0	1.27	0.76	0.59	0.49
Talbert	Hawk	12	0.74	0.74	0.74	0.74	3.37	3.37	3.37	3.37
Upland	Hawkins	12	1.7	1.7	1.7	1.7	2.71	2.71	2.71	2.45
Yukon	Hawthorne	16	3.21	3.21	3.21	3.21	7.94	6.02	5.39	5.01
Inglewood	Hayden	4.16	0.58	0	0	0	0.78	0	0	0
Oxnard	Haydock	4.16	0.82	0.82	0.82	0.82	1.23	0.85	0.65	0.55
Venida	Hays	12	0	0	0	0	0	0	0	0
Fremont	Hayward	4.16	0.85	0.85	0.85	0.85	1.28	1.09	0.68	0.57
Francis	Hazel	12	3.02	3.02	3.02	3.02	3.3	3.3	3.3	3.3
Chestnut	Hazelnut	12	2.54	2.54	2.54	2.54	3.49	3.49	3.49	3.44
Alessandro	Heacock	12	2.18	2.18	2.18	2.18	3.38	3.38	3.38	3.08
Heartwell P.T.	Heartwell	4.16	0.43	0	0	0	0.93	0	0	0
Alder	Heather	12	1.73	1.73	1.73	1.73	3.36	3.36	3.36	3.23
Randsburg	Heavy	33	0	0	0	0	0	0	0	0
Cady	Hector	12	0	0	0	0	0	0	0	0
Santa Fe Springs	Hedge	12	2.54	0	0	0	3.49	3.49	3.49	3.49
Maxwell	Heers	12	0	0	0	0	3.12	3.12	3.12	3.11
Bain	Heftler	12	0.31	0.31	0.31	0.31	3.49	3.49	3.49	2.97
Oasis	Heights	12	0.13	0.13	0.13	0.13	0	0	0	0
Oceanview	Heil	12	2.87	2.87	2.87	2.87	3.45	3.45	3.45	3.45
Trophy	Heisman	12	0	0	0	0	3.01	3.01	2.75	2.28
Santa Barbara	Helena	4.16	0.18	0.18	0.18	0.18	0	0	0	0
Skylark	Helenka	12	4.98	4.98	4.98	4.98	3.23	3.23	3.08	2.6
Bunker	Helicopter	12	0	0	0	0	3.16	3.16	2.56	2.17
Minneola	Helios	12	0	0	0	0	0	0	0	0
Nola	Helium	16	3.02	0	0	0	6.94	0	0	0
Ramona	Hellman	4.16	0	0	0	0	0.6	0	0	0
Newmark	Helm	16	2.1	2.1	2.1	2.1	8.25	6.92	6.2	5.76
Firehouse	Helmet	12	0.99	0.99	0.99	0.99	3.49	3.49	3.49	3.49
Mayberry	Hemacinto	12	0	0	0	0	3.05	3.05	3.05	3.05
Porterville	Henderson	12	0	0	0	0	0	0	0	0
Belvedere	Herbert	4.16	1.01	0	0	0	1.27	0	0	0
Hesperia	Hercules	12	0	0	0	0	3.04	3.04	3.04	3.04
Bovine	Hereford	12	2.29	2.29	2.29	2.29	3.43	3.43	3.43	3.43
Redondo	Hermosa	4.16	0	0	0	0	1.13	0.68	0.48	0.4
Bunker	Hero	12	2.32	2.32	2.32	2.32	3.3	3.3	2.85	2.38
Merced	Herring	12	1.24	1.24	1.24	1.24	3.4	3.4	3.4	3.4
Del Amo	HersheyOld	12	0	0	0	0	3.49	0	0	0
Cardiff	Herz	12	4.82	4.82	3.02	3.02	1.02	1.02	1.01	0.85
Nelson	Hewitt	12	6.35	3.02	3.02	3.02	3.42	3.42	3.42	3.13
Chestnut	Hexnut	12	2.54	2.54	2.54	2.54	3.44	3.44	3.44	3.12
Artesia	Hibbing	4.16	1.01	0	0	0	0.71	0	0	0
Kempster	Hibiscus	4.16	0.33	0.33	0.33	0.33	1.17	0.73	0.56	0.48
Madrid	Hickory	4.16	0	0	0	0	1.25	0.77	0.55	0.46
Belvedere P.T.	Hicks	4.16	0.21	0	0	0	0.77	0	0	0
Granada	Hidalgo	4.16	0.62	0	0	0	0.67	0	0	0
Liberty	Higby	12	0	0	0	0	0	0	0	0
High P.T.	High	4.16	0	0	0	0	0	0	0	0
High School P.T.	HighSchool	2.4	0.58	0	0	0	0.82	0	0	0
Bloomington	Highball	12	1.21	1.21	1.21	1.21	2.7	2.7	2.7	2.38
Rush	Highcliff	16	0	0	0	0	9.07	6.82	6.18	5.72
Diamond Bar	Highnoon	12	0	0	0	0	3.39	3.39	3.17	2.69
Saticoy	Highway	16	3.61	3.61	3.61	3.61	6.41	5.37	4.84	4.5
Inyokern	HighwaySix	12	0	0	0	0	0	0	0	0
Borrego	Higo	12	3.02	3.02	3.02	3.02	3.35	3.35	3.35	3.35
Ridgecrest	Hildreth	4.8	0	0	0	0	0	0	0	0
Manhattan	Hill	4.16	1.13	0	0	0	0.83	0.49	0.39	0.33
La Canada	Hillard	4.16	0.36	0.36	0.36	0.36	1.2	0.74	0.58	0.49
Thousand Oaks	Hillcrest	16	0	0	0	0	7.93	6.13	5.52	5.13
Solemint	Hillfield	16	2.89	2.89	2.89	2.89	8.23	5.42	5.42	5.03
Coffee	Hills	12	10	10	10	10	3.44	3.44	3.44	3.28
Victoria	Hillside	16	3.94	0	0	0	6.65	0	0	0
Sangar	Hilltop	4.16	0	0	0	0	0.77	0.52	0.41	0.34
Amalia	Hillview	4.16	0.02	0	0	0	0.73	0	0	0

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Beverly	Hilton	16	0	0	0	0	7.12	6	5.45	5.02
Mira Loma	Himalayas	12	0	0	0	0	3.15	3.15	3.15	3.15
Hi Desert	Himo	33	6.69	6.69	6.69	6.69	0	0	0	0
Felton	Hindry	4.16	1.01	0	0	0	0.73	0	0	0
Irvine	Hines	12	2.38	2.38	2.38	2.38	1.82	1.82	1.77	1.49
Ravendale	Hinshaw	16	0	0	0	0	8.09	5.49	5.49	5.49
Brookhurst	Hirsch	12	0.83	0.83	0.83	0.83	3.13	3.13	3.13	2.87
Ivyglen	Hitch	12	0	0	0	0	3.03	3.03	3.03	2.86
Cherry	Hoback	12	3.78	0	0	0	3.48	0	0	0
Fruitland	Hobart	16	3.84	3.84	3.84	3.84	9.4	7.9	7.09	6.57
Railroad	Hobo	12	0	0	0	0	3.49	3.49	3.49	3.49
Pixley	Hobson	12	0	0	0	0	0	0	0	0
Archibald	Hofer	12	0	0	0	0	2.35	2.35	2.35	2.29
Lafayette	Hogan	12	4.26	3.02	3.02	3.02	3.37	3.37	3.37	3.37
Westgate	Holbrook	4.16	0.09	0.09	0.09	0.09	1.18	0.65	0.65	0.55
Badillo	Hollenbeck	4.16	0	0	0	0	0.62	0	0	0
Basta	Holloway	4.16	0.14	0	0	0	0.77	0	0	0
Anita	Holly	4.16	0.02	0.02	0.02	0.02	1.05	0.56	0.56	0.47
Del Rosa	HollyVista	12	2.13	2.13	2.13	2.13	3.26	3.26	3.26	2.89
Fairfax	Hollywood	16	0	0	0	0	13.09	7.21	6.45	5.99
Calden	Holmes	16	5.76	3.97	3.97	3.94	9.46	7.92	7.12	6.62
Tippecanoe	Holstein	4.16	0.74	0	0	0	1.28	0.71	0.71	0.59
Concho	Hombre	12	0	0	0	0	0	0	0	0
State Street	Home	12	3.02	0	0	0	3.38	3.38	3.38	3.38
Cudahy	HomeGardens	4.16	0.47	0.47	0.47	0.47	0.77	0.77	0.62	0.52
Lemon Cove	Homer	12	0	0	0	0	0	0	0	0
Imperial	Hondo	4.16	0.97	0.97	0.97	0.97	1.26	1.13	0.67	0.57
El Casco	Honeycrisp	12	1.08	1.08	1.08	1.08	2.85	2.85	2.64	2.21
Bradbury	Honeywell	16	0	0	0	0	7.13	5.99	5.47	5.02
Rosemead	Honor	16	0	0	0	0	7.38	5.97	5.39	5
Gilbert	Hook	12	1.71	1.71	1.71	1.71	3.49	3.49	3.49	3.49
Hook Creek P.T.	HookCreek	2.4	0.4	0	0	0	0.65	0	0	0
Newbury	Hooligan	16	0	0	0	0	5.32	4.59	4.01	3.72
Naomi	Hooper	4.16	0	0	0	0	0.75	0	0	0
Alhambra	Hoover	4.16	1.22	1.01	1.01	1.01	1.2	0.78	0.59	0.5
Etiwanda	Hope	12	1.2	1.2	1.2	1.2	2.36	1.52	1.52	1.52
Shawnee	Hopi	12	0.04	0.04	0.04	0.04	3.44	3.44	3.44	3.44
Bloomington	Hopper	12	0	0	0	0	3.29	3.29	3.04	2.58
Valdez	Horizon	16	0	0	0	0	6.68	5.47	4.94	4.58
Silver Spur	Horn	12	0	0	0	0	0	0	0	0
Valdez	Horntoad	16	1.74	1.74	1.74	1.74	5.07	4.26	3.9	3.57
Estrella	Horoscope	12	0	0	0	0	3.29	3.29	3.29	3.09
Canyon	Horseshoe	12	0.6	0.6	0.6	0.6	3.04	3.04	3.04	2.75
Fogarty	Horton	12	0	0	0	0	3.49	3.49	3.49	3.23
Firehouse	Hose	12	1.34	1.34	1.34	1.34	0	0	0	0
Del Rosa	Hospat	12	0	0	0	0	3.38	3.38	3.38	3.38
Pierpont	Hospital	4.16	0.31	0.31	0.31	0.31	0.89	0.51	0.39	0.33
Royal	Hoss	16	0	0	0	0	7.79	4.61	4.2	3.86
Santa Barbara	HotSprings	16	2.72	2.72	2.72	2.72	6.54	5.52	4.96	4.6
Upland	Hotpoint	12	4.16	4.16	3.02	3.02	3.48	3.48	3.48	3.48
Pioneer	Houghton	4.16	0	0	0	0	1.26	0.9	0.65	0.55
Poplar	Houston	12	0	0	0	0	0	0	0	0
Del Rosa	Hovatter	12	0.68	0.68	0.68	0.68	2.99	2.99	2.99	2.61
Redman	Hovey	12	4.21	4.21	3.02	3.02	0.01	0.01	0.01	0.01
Verdant	Howbuck	12	3.48	3.48	0	0	3.49	3.49	3.49	3.49
Eisenhower	Howitzer	12	3.02	0	0	0	3.44	3.44	3.44	3.44
Fremont	HubCity	16	5.32	5.32	5.32	3.97	7.44	6.3	5.64	5.23
Ritter Ranch	Huckleberry	12	5.33	4.54	0	0	3.49	2.76	2.19	1.84
Bryan	Hudson	12	2.09	2.09	2.09	2.09	3.28	3.28	3.28	3.17
Tortilla	Huevos	12	0	0	0	0	0	0	0	0
Alder	Huff	12	0.42	0.42	0.42	0.42	3.37	3.37	3.37	2.86
Del Sur	HughesLake	12	0.75	0.75	0.75	0.75	0	0	0	0
Murrietta	Hugo	12	6.82	3.02	0	0	2.99	2.99	2.99	2.99
Inyokern	Hulsey	33	0	0	0	0	0	0	0	0
Dryden P.T.	Hulstein	12	10	0	0	0	3.49	0	0	0
Moraga	Humber	12	1.06	1.06	1.06	1.06	3.32	3.32	3.32	3.32
Wave	Humble	12	1.44	0	0	0	3.47	0	0	0
Bicknell	Humphrey	4.16	0	0	0	0	1.07	0.7	0.46	0.46
Fullerton	Hunt	12	0	0	0	0	3.25	3.25	3.25	2.94
Moraga	Hunter	12	3.02	3.02	3.02	3.02	3.02	3.02	3.02	3.02
Casa Diablo	Hurley	12	0	0	0	0	0	0	0	0
Great Lakes	Huron	12	2.57	2.57	2.57	2.57	1.71	1.71	1.36	1.14
Yorba Linda	Hurricane	12	0	0	0	0	3.13	3.13	3.02	2.53
San Marcos	Hurst	16	3.97	3.97	3.97	3.97	5.05	4.24	3.83	3.56
Bradbury	Hurstview	16	1.93	1.93	1.93	1.93	8.08	6.77	6.16	5.67
Moulton	Huskie	12	0	0	0	0	3.49	3.49	3.49	3.49
Highland	Hutchins	12	3.13	3.02	3	3	2.77	2.77	2.77	2.77
Hutt P.T.	Hutt	12	0	0	0	0	0	0	0	0
Inglewood	HydePark	4.16	0.58	0	0	0	1.11	0.82	0.59	0.49
Firehouse	Hydrant	12	0	0	0	0	2.77	2.77	2.77	2.77

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Greening	Ibex	12	0.87	0.87	0.87	0.87	3.41	3.41	3.41	3.41
Maraschino	Ida	12	0	0	0	0	3.1	3.1	3.1	2.71
La Habra	Idaho	12	0.94	0.94	0.94	0.94	2.97	2.97	2.97	2.97
Idyllbrook P.T.	Idyllbrook	2.4	0.38	0	0	0	0.97	0	0	0
Eisenhower	Ike	12	3.02	3.02	3.02	3.02	2.15	2.15	2.15	2.15
Moneta	Illinois	4.16	0.18	0.18	0.18	0.18	1.18	0.66	0.52	0.44
Archibald	Imbach	12	2.13	2.13	2.13	2.13	3.28	3.28	3.22	2.7
Indian Wells	Inca	12	0	0	0	0	0	0	0	0
Palm Village	Inch	12	0	0	0	0	0	0	0	0
Peyton	Independence	12	0.63	0.63	0.63	0.63	3.27	3.27	2.78	2.32
Belvedere	Indiana	4.16	2.3	0	0	0	1.29	0	0	0
Trask	Indianapolis	12	0	0	0	0	3.39	3.39	2.98	2.49
Firehouse	Inferno	12	0	0	0	0	3.48	3.48	3.48	3.48
Paularino	Inlet	4.16	0	0	0	0	0.83	0.42	0.31	0.26
Baker	Inn	12	0	0	0	0	0	0	0	0
Kernville	Intake	12	0	0	0	0	0	0	0	0
Timoteo	Intern	12	0	0	0	0	3.03	3.03	3.03	3.03
Roadway	International	12	3.41	3.41	3.41	3.02	3.49	3.49	3.3	2.77
Corona	Interpace	33	1.01	1.01	1.01	1.01	27	15.26	11.37	8.77
Sepulveda	Interstate	16	2.81	0	0	0	7.48	0	0	0
Newbury	Intrepid	16	0	0	0	0	4.95	3.96	3.57	3.31
Devers	Invader	12	4.54	4.54	3.67	3.67	0	0	0	0
Quartz Hill	Invention	12	0	0	0	0	2.22	2.22	2.22	2.22
Mt. Tom	InyoLumber	12	0	0	0	0	0	0	0	0
Hanford	Iona	12	0	0	0	0	0	0	0	0
Somerset	Iowa	4.16	0	0	0	0	1.2	0.84	0.66	0.56
Gage	Ira	4.16	0	0	0	0	1.09	0.72	0.56	0.47
Modena	Iran	12	1.98	1.98	1.98	1.98	2.89	2.89	2.89	2.65
Lark Ellen	Irene	12	1.71	0	0	0	3.49	0	0	0
Arch Beach	Iris	4.16	1.01	0	0	0	0.88	0	0	0
Lighthipe	Irish	12	1.93	0	0	0	3.49	0	0	0
Limestone	Iron	12	3.79	3.79	3.79	3.02	3.49	3.49	3.49	3.49
Bloomington	Ironhorse	12	3.42	3.42	3.02	3.02	3.39	3.39	3.39	3.22
Santa Rosa	Irontree	12	0	0	0	0	0	0	0	0
Alessandro	Ironwood	33	8.38	8.38	8.38	8.38	20.47	15.15	11.12	8.74
Shandin	Irvington	12	4.78	4.78	4.78	4.78	3.45	3.45	3.45	3.45
Santa Monica	IrwinHts	4.16	0.73	0	0	0	0.66	0	0	0
Proctor	Isis	12	2.33	2.33	2.33	2.33	3.49	3.49	3.49	3.14
Edgewater	Island	4.16	1.4	0	0	0	0.96	0	0	0
Kramer	Isner	33	0	0	0	0	0	0	0	0
Modena	Israel	12	0	0	0	0	2.74	2.74	2.74	2.74
Monrovia	Ivy	4.16	0	0	0	0	0.64	0	0	0
Saugus	JBsherman	16	2.77	2.77	2.77	2.77	7.09	5.66	5.11	4.74
Tamarisk	Jacaranda	12	0	0	0	0	0	0	0	0
Beaumont	JackRabbit	4.16	1.01	0	0	0	0.63	0	0	0
Downs	JackRanch	12	0	0	0	0	0	0	0	0
Lancaster	Jackman	12	0.51	0.51	0.51	0.51	2.81	2.81	2.81	2.46
Jackpot P.T	Jackpot	25	0	0	0	0	3.49	3.49	3.49	3.49
Culver	Jackson	16	3.94	0	0	0	6.9	0	0	0
Friendly Hills	Jacmar	4.16	0	0	0	0	0.85	0.85	0.69	0.56
Marion	Jacque	12	0.78	0.78	0.78	0.78	3.18	3.18	3.18	3.18
Crown	Jade	12	1.49	1.49	0	0	3.3	3.3	3.3	3.3
Lampson	Jaguar	12	0	0	0	0	3.49	3.49	3.49	3.49
Smiley	Jake	4.16	0.57	0.57	0.57	0.57	0.97	0.62	0.49	0.41
Ely	Jamaica	12	2.41	2.41	2.41	2.41	3.4	3.4	3.4	3.4
Crown	Jamboree	12	0.38	0.38	0.38	0.38	3.34	3.34	3.34	2.81
Imperial	James	4.16	0.24	0.24	0.24	0.24	1.22	0.61	0.49	0.41
Santa Barbara	Jameson	16	0	0	0	0	7.61	6	5.46	5.04
Carmenita	Janae	12	2.45	2.45	2.45	2.45	3.4	3.4	3.4	3.4
Ditmar	Janice	4.16	0.72	0	0	0	0.68	0	0	0
Moorpark	Janss	16	0	0	0	0	7.21	5.92	5.36	4.96
Lafayette	January	12	1.59	1.59	1.59	1.59	3.32	3.17	2.55	2.13
Dalton	Jarvis	12	1.24	1.24	1.24	1.24	0	0	0	0
Quinn	Jasmine	12	0	0	0	0	0	0	0	0
Redlands	Jasper	12	0.76	0.76	0.76	0.76	2.85	2.85	2.85	2.43
Lennox	Java	4.16	1.01	0	0	0	0.64	0	0	0
Cantil	Jawbone	12	0	0	0	0	0	0	0	0
Universal	Jaws	12	3.02	3.02	3.02	3.02	3.39	3.39	3.39	3.39
Archline	Jaybird	12	0.45	0.45	0.45	0.45	3.27	3.27	3.27	3.27
Passons	Jayblue	12	1.72	0	0	0	3.44	0	0	0
Bristol	Jaycee	4.16	1.66	0	0	0	1.26	0	0	0
Basta	Jaymac	4.16	0	0	0	0	0.61	0	0	0
Team	Jazz	12	0.12	0.12	0.12	0.12	3.37	3.37	3.37	3.37
Shuttle	Jedi	12	0	0	0	0	0.85	0.85	0.75	0.64
Arrowhead	Jeep	12	1.99	1.99	1.99	1.99	3.44	3.44	3.44	3.21
Irvine	Jeffrey	12	0.03	0.03	0.03	0.03	2.83	2.83	2.21	1.83
Yucca	Jellystone	12	0.91	0.91	0.91	0.91	2.61	2.61	2.19	1.85
Carson	Jenkins	16	0	0	0	0	9.01	6.26	5.54	5.15
Converse Flats	JenksLake	12	0.96	0.96	0.96	0	3.49	3.49	3.49	3.49
Los Cerritos	Jennings	12	0.7	0.7	0.7	0.7	3.42	3.42	3.42	3.4

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Lucas	Jepson	12	0	0	0	0	3.43	3.43	3.15	2.67
Trask	Jerome	12	1.05	1.05	1.05	1.05	3.45	3.45	3.45	3.39
Valley	Jerry	12	6.1	6.1	6.1	3.02	3.43	3.43	3.14	2.65
Tenaja Test	Jerusalem	12	1.41	0	0	0	3.04	3.04	2.8	2.37
Apple Valley	Jess	12	2.07	2.07	2.07	2.07	1.56	1.37	1.07	0.88
Jessie P.T.	Jessie	4.16	0	0	0	0	0	0	0	0
Floraday	Jessup	4.16	0	0	0	0	0.63	0	0	0
Parker Strip	JetSki	12	1.08	1.08	1.08	1.08	3.49	3.49	3.49	3.21
Edgewater	Jetty	4.16	1.01	0	0	0	0.6	0	0	0
Stewart	Jimmy	12	0	0	0	0	3.32	3.32	3.32	3.19
Mentone	Jims	12	3.08	3.08	3.02	3.02	3.34	3.34	3.34	3.34
Fairview	Joaquin	12	0.37	0.37	0.37	0.37	2.75	2.75	2.75	2.75
Job P.T.	Job	2.4	0.04	0.04	0.04	0.04	1	0.68	0.53	0.45
Joburg P.T.	Joburg	2.4	0	0	0	0	0	0	0	0
Moneta	Johanna	4.16	0	0	0	0	0.9	0.9	0.7	0.58
Newbury	Johnboy	16	2.83	2.83	2.83	2.83	7.51	6.43	5.82	5.23
Johnsondale P.T.	Johnsondale	4.16	0	0	0	0	0	0	0	0
Cortez	Jojo	12	0.64	0	0	0	3.49	0	0	0
El Casco	Jonagold	12	4.02	4.02	4.02	3.78	3.41	3.41	2.92	2.34
Ocean Park	Jones	4.16	0.42	0	0	0	0.67	0	0	0
Trask	Joplin	12	0.74	0.74	0.74	0.74	3.35	3.35	3.35	3.35
Glennville	Jordan	12	0	0	0	0	0	0	0	0
Ravendale	Josard	16	3.14	3.14	3.14	3.14	7.32	6.13	5.56	5.13
Lancaster	Joshua	12	3.02	3.02	3.02	3.02	2.12	2.12	2.12	2.12
Clark	Josie	4.16	0	0	0	0	0.65	0	0	0
Bandini	Joslyn	16	2.42	2.42	2.42	0	7.91	6.64	5.98	5.55
Porterville	Josten	12	0	0	0	0	0	0	0	0
Corona	Joy	4.16	1.11	1.11	1.11	1.11	1.29	0.84	0.65	0.55
Arcadia	Joyce	4.16	0	0	0	0	1.21	0.77	0.6	0.51
Hemet	Juanita	4.8	0	0	0	0	1.29	0	0	0
Brea	Juarez	12	0	0	0	0	3.12	3.12	3.12	2.98
Maraschino	Jubilee	12	1.32	1.32	1.32	1.32	3.32	3.32	3.32	3.32
Felton	Judah	4.16	0	0	0	0	1.14	1.02	0.6	0.51
Cornuta	Judge	12	1.39	0	0	0	3.46	0	0	0
Redlands	Judson	12	0	0	0	0	3.21	3.21	3.21	3.21
Ordway	Judy	12	0	0	0	0	0	0	0	0
Narrows	Julep	12	0	0	0	0	3.49	0	0	0
Haskell	Julius	16	1.53	1.53	1.53	1.53	6.56	5.28	4.79	4.43
Yukon	Juneau	4.16	1.01	1.01	1.01	1.01	1.19	0.54	0.54	0.45
Randall	Junior	12	0	0	0	0	2.95	2.95	2.95	2.95
Nuevo	Juniper	12	2.2	2.2	2.2	2.2	3.45	3.45	3.45	2.93
Bluff Cove	Jupiter	4.16	0.36	0.36	0.36	0.36	0.72	0.48	0.39	0.32
Narod	Jurupa	12	0.84	0.84	0.84	0.84	3.44	3.44	3.44	3.44
Cornuta	Jury	12	0.73	0.73	0.73	0.73	3.4	3.4	3.4	3.4
Cardiff	Justice	12	1.21	1.21	1.21	1.21	3.49	3.49	3.49	3.35
Mayberry	Kadice	12	0	0	0	0	2.96	2.96	2.96	2.5
Francis	Kadota	12	0	0	0	0	3.37	3.37	3.37	2.91
Chiquita	Kahlua	12	1.25	1.25	1.25	1.25	3.22	3.22	3.06	2.55
Declez	Kaiser	12	0	0	0	0	0.19	0.19	0.18	0.13
San Fernando	Kalisher	16	1.7	1.7	1.7	1.7	7.98	6.68	6.02	5.59
Calden	Kalmia	16	5.95	3.97	3.97	3.97	8.41	7.01	6.33	5.88
Malibu	Kanan	16	0	0	0	0	7.18	5.84	5.31	4.88
Pearl	Kansas	4.16	0	0	0	0	0.6	0	0	0
Telegraph	Kappa	12	0.75	0.75	0.75	0	3.49	3.49	3.49	3.49
Marion	Karen	12	0	0	0	0	3.19	3.19	3.19	3.19
Victorville	Kasota	12	0.07	0.07	0.07	0.07	2.6	2.6	2.6	2.42
Cypress	Katella	12	0.17	0.17	0.17	0.17	2.89	2.89	2.89	2.89
Harding	Katherine	4.16	1.01	0	0	0	0.64	0	0	0
Felton	Kathleen	16	8.6	3.97	3.97	3.97	8.86	7.3	6.56	6.07
Anita	Kauffman	4.16	0.49	0	0	0	0.69	0	0	0
Alhambra	Kay	16	0	0	0	0	7.86	6.44	5.82	5.4
Manhattan	Keats	4.16	1.4	0	0	0	1.04	0	0	0
Quartz Hill	Keefer	12	2.14	2.14	2.14	2.14	1.87	1.87	1.87	1.57
Pico	Keel	12	0	0	0	0	3.49	3.49	3.49	3.49
Irvine	Keeline	12	0.56	0.56	0.56	0.56	3.28	3.28	3.28	2.99
Monolith	Keene	12	3.02	3.02	3.02	3.02	0	0	0	0
Sunnyside	Keever	4.16	0	0	0	0	0.68	0	0	0
Garvey	Keim	4.16	0.51	0.51	0	0	1.17	1.17	0.66	0.55
Westgate	Keith	4.16	0.07	0.07	0.07	0.07	1.14	0.57	0.57	0.48
Lighthipe	Kelber	12	0	0	0	0	3.49	3.49	3.49	3.49
Auld	Keller	12	0	0	0	0	2.25	2.25	1.97	1.65
Daggett	Kelly	4.16	0	0	0	0	0	0	0	0
La Mirada	Kelsey	12	3.46	3.02	3.02	3.02	3.37	3.37	3.37	3.37
Cabrillo	Kelvin	12	3.02	0	0	0	3.49	0	0	0
Sepulveda	Kelvinator	16	3.97	3.97	3.97	3.97	8.65	7.27	6.57	6.07
Repetto	Kenbo	4.16	0.68	0.68	0.68	0.68	1.2	0.63	0.63	0.53
Stoddard	Kendell	4.16	0.98	0.98	0	0	0.9	0.9	0.59	0.5
Newmark	Kenmore	4.16	0	0	0	0	0.72	0	0	0
Inyokern	Kennedy	33	0	0	0	0	0	0	0	0
Floraday	Kenney	4.16	0	0	0	0	1.24	0.87	0.7	0.58

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Phelan	Keno	12	1.75	1.75	1.75	1.75	0	0	0	0
Pomona	Kenoak	4.16	0.43	0.43	0.43	0.43	1.28	0.89	0.65	0.55
Carolina	Kentucky	12	2.55	2.55	2.55	2.55	3.35	3.35	3.35	3.35
Bullis	Kenwood	16	7.47	3.97	3.97	3.97	8.6	7.28	6.31	5.84
Roadway	Kenworth	12	1.38	1.38	1.38	1.38	0	0	0	0
Archline	Kenyon	12	1.01	1.01	1.01	1.01	3.17	3.17	3.17	2.65
Nogales	Kermit	12	0	0	0	0	3.35	3.35	3.35	2.93
Hesperia	Kern	12	0.12	0.12	0.12	0.12	2.65	2.65	2.12	1.8
Jersey	Kernan	16	0.63	0.63	0.63	0.63	7.77	6.54	5.89	5.47
Fogarty	Kerry	12	0	0	0	0	3.49	3.49	3.49	3.49
Milliken	Kessler	12	0	0	0	0	3.49	3.49	3.3	2.78
Bolsa	Ketch	12	0	0	0	0	2.23	2.01	1.59	1.35
Crown	Kewamee	12	0.82	0.82	0.82	0.82	3.28	3.01	2.25	1.9
San Marino	Kewen	4.16	0.35	0.35	0	0	1.16	0.84	0.52	0.44
Neptune	Keystone	4.16	0.29	0.29	0.29	0.29	1.23	0.85	0.7	0.56
Washington	Kick	12	1.74	1.74	1.74	1.74	3.49	3.49	3.49	3.49
Yucca	KickapooTrail	12	1.62	1.62	1.62	1.62	2.86	2.45	1.95	1.61
Cameron	Kidd	12	6.41	6.41	6.41	3.02	3.49	3.49	3.49	3.49
Arcadia	Kieway	16	3.61	3.61	3.61	3.61	9.35	7.88	7.01	6.51
Murphy	Kilkenny	12	0	0	0	0	3.1	3.04	2.4	2.04
Sunnyside	Killdee	4.16	0	0	0	0	1.18	0.84	0.59	0.5
Murphy	Kilroy	12	1.88	1.88	1.88	1.88	3.44	3.44	3.44	3.21
Highland	Kilts	12	0	0	0	0	2.86	2.86	2.71	2.28
Kimberly P.T.	Kimberly	2.4	0.4	0	0	0	0.75	0	0	0
Cajalco	Kimdale	12	0.86	0.86	0.86	0.86	0.78	0.63	0.5	0.42
Victoria	King	16	3.97	3.97	3.97	3.97	7.17	5.95	5.36	4.98
Kimball	Kingcobra	12	0	0	0	0	3.42	3.42	3.42	2.94
Ravendale	Kinghurst	4.16	0	0	0	0	1.22	0.73	0.57	0.49
Corona	Kingsford	12	0	0	0	0	2.04	2.04	2.04	1.88
San Antonio	Kingsley	12	0.35	0.35	0.35	0.35	3.38	3.38	3.38	3.38
Alessandro	Kingsway	12	1.32	1.32	1.32	1.32	3.4	3.4	3.4	3.4
Lancaster	Kingtree	12	2.92	0	0	0	2.93	0	0	0
Laguna Bell	Kinmont	16	7.93	0	0	0	7.44	0	0	0
Eaton	Kinneloa	16	0.05	0.05	0.05	0.05	6.79	5.67	5.12	4.76
Gorman	Kinsey	12	3.02	3.02	3.02	3.02	3.48	2.64	2.08	1.76
Apple Valley	Kiowa	12	1.5	1.5	1.5	1.5	2.44	2.44	2.39	1.99
Nelson	Kirby	12	0	0	0	0	2.31	2.31	2.31	2.22
Fogarty	Kleven	12	0	0	0	0	3.49	2.77	2.23	1.86
Gisler	Klingon	12	0	0	0	0	2.76	2.76	2.76	2.76
Kliss P.T.	Kliss	4.16	1.65	0	0	0	0.94	0	0	0
Upland	Klusman	4.16	0.07	0	0	0	0.63	0	0	0
Kneeland P.T.	Kneeland	4.16	0.41	0	0	0	1.28	0	0	0
Rancho	Knolls	12	2.19	2.19	2.19	2.19	3.23	3.23	2.98	2.51
La Palma	Knott	12	1.07	1.07	1.07	1.07	3.36	3.36	3.36	3.2
Victor	Koala	12	2.07	2.07	2.07	2.07	0	0	0	0
Fruitland	Kobe	16	3.97	0	0	0	7.15	0	0	0
Coffee	Kona	12	1.13	1.13	1.13	1.13	0.97	0.97	0.77	0.65
Shuttle	Konobie	12	1.02	1.02	1.02	1.02	2.17	2.17	2.03	1.72
Stewart	Kordell	12	1.03	1.03	1.03	1.03	3.44	3.44	3.44	3.44
Modena	Korea	12	0	0	0	0	2.61	2.61	2.61	2.53
Lawndale	Kornblum	4.16	0.72	0.72	0.72	0.72	0.74	0.74	0.59	0.49
Glen Avon	Kraft	12	2.9	2.9	2.9	2.9	3.22	3.22	3.22	2.74
San Dimas	Kranzer	12	0.95	0	0	0	3.33	0	0	0
Ripley	Kratka	12	2.07	2.07	2.07	2.07	3.45	2.55	2.02	1.69
Marion	Kristen	12	1.1	1.1	1.1	1.1	2.77	2.77	2.77	2.77
Santiago	Krona	12	0	0	0	0	3.33	3.33	3.33	2.75
Archibald	Kropp	12	0	0	0	0	2.49	2.49	2.24	1.88
MacArthur	Krueger	12	1.67	1.67	1.67	1.67	3.31	3.31	3.31	3.01
Limestone	Krypton	12	0	0	0	0	3.49	3.49	3.49	3.49
Santa Susana	Kuehner	16	0	0	0	0	7.37	5.93	5.22	4.84
Kuffel P.T.	Kuffel	2.4	0.27	0	0	0	0.61	0	0	0
Murrietta	Kulberg	12	0	0	0	0	2.64	2.64	2.64	2.64
Citrus	Kumquat	12	0.05	0.05	0.05	0.05	3.4	3.4	3.4	3.2
Santiago	Kuna	12	1.24	1.24	1.24	1.24	2.98	2.98	2.91	2.43
Santiago	Kwacha	12	5.2	5.2	5.2	3.02	3.49	3.49	3.49	3.34
Walnut	Kwis	12	0.08	0.08	0.08	0.08	3.07	3.07	2.81	2.38
Quinn	Kyte	12	0	0	0	0	0	0	0	0
Fairfax	LaBrea	4.16	0.07	0	0	0	0.79	0	0	0
La Cumbre P.T.	LaCumbre	4.16	1.01	1.01	1.01	1.01	0.79	0.53	0.42	0.35
Archline	LaGrande	12	0.36	0.36	0.36	0.36	2.63	2.63	2.58	2.18
Potrero	LaMancha	16	0.48	0.48	0.48	0.48	6.24	5.02	4.39	4.05
Victorville	LaPaz	12	0	0	0	0	3.48	3.48	3.48	3.28
Beverly	LaPeer	16	0.2	0.2	0.2	0.2	9.67	8.03	7.19	6.66
Anita	LaPorte	16	0	0	0	0	7.52	6.29	5.7	5.28
Redlands	LaPosada	4.16	0	0	0	0	1.22	0.85	0.67	0.56
San Gabriel	LaPresa	4.16	0	0	0	0	1.03	0.55	0.55	0.46
Santa Rosa	LaQuinta	33	0	0	0	0	0	0	0	0
Dalton	LaRica	12	3.77	3.77	3.02	3.02	3.49	3.49	3.49	3.49
Cabrillo	LaSalle	12	2.35	2.35	2.35	2.35	3.39	3.39	3.39	3.39
Pedley	LaSierra	12	7.31	7.31	6.8	6.8	3.45	3.45	3.13	2.62

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Potrero	LaVaca	16	2.11	2.11	2.11	2.11	11.56	6.24	5.62	5.23
Pedley	Lab	12	0.47	0.47	0.47	0.47	3.01	3.01	2.67	2.13
Lacresta P.T.	Lacresta	12	0.27	0.27	0.27	0.27	2.68	2.65	2.04	1.73
Firehouse	Ladder	12	6.5	0	0	0	3.49	0	0	0
Windsor Hills	Ladera	4.16	1.11	1.11	1.01	1.01	1.25	0.82	0.64	0.53
Dalton	Lager	12	3.02	0	0	0	3.49	0	0	0
Blythe City	Lagoon	33	8.38	8.38	8.38	8.38	23.66	15.55	7.85	7.85
Santa Fe Springs	Laird	12	0	0	0	0	3.4	3.4	3.4	3.36
Fair Oaks	Lake	4.16	0.16	0.16	0.16	0.16	1.14	0.68	0.53	0.45
Elsinore	Lakeland	12	2.47	2.47	2.47	2.47	3.15	3.08	2.5	2.07
Team	Lakers	12	0	0	0	0	3.37	3.37	3.37	3.37
Rancho	Lakota	12	1.7	1.7	1.7	1.7	2.82	2.82	2.4	2.04
Eaton	Lamanda	16	3.21	3.21	3.21	3.21	9.64	7.21	6.3	5.86
Pepper	Lancers	12	1.64	1.64	1.64	1.64	3.4	3.4	3.4	3.02
Farrell	Landau	12	1.1	1.1	1.1	1.1	3.01	3.01	3.01	3.01
Nugget	Landers	25	2.02	2.02	2.02	2.02	0.31	0.31	0.31	0.31
Alessandro	Landmark	12	0	0	0	0	2.39	2.39	2.39	2.25
La Canada	Lane	4.16	0.13	0.13	0.13	0.13	0.91	0.58	0.46	0.39
Thousand Oaks	Langer	16	4.62	3.97	3.97	3.97	7.59	5.98	5.42	5.02
Ellis	Langley	12	0	0	0	0	3.05	3.05	3.05	3.05
Fremont	Lantana	16	11.34	11.34	7.93	4.53	9.55	7.71	6.99	6.44
Sharon	Lanterman	4.16	0.38	0.38	0.38	0.38	0.88	0.54	0.4	0.34
Mariposa	Lanza	12	0	0	0	0	0	0	0	0
Maraschino	Lapins	12	0	0	0	0	2.94	2.82	2.17	1.83
Fairfax	Larabee	16	0	0	0	0	8.54	7.15	6.5	5.98
Calectric	Larch	33	5.4	5.4	5.4	5.4	27	21.09	14.4	11.47
Imperial	Laredo	12	1.82	1.82	1.82	1.82	3.47	3.47	3.47	3.47
Quartz Hill	Lariat	12	3.46	0	0	0	3.02	0	0	0
Wrightwood	Lark	2.4	0.21	0.21	0.21	0.21	1.26	0.86	0.67	0.56
Carodean	Larrea	12	2.31	2.31	2.31	2.31	2.61	2.61	2.4	2.04
Somerset	Larry	12	4.37	4.37	4.37	4.21	3.45	3.45	3.45	3.45
Bryan	Larthien	12	2.99	2.99	2.99	2.99	3.49	3.49	3.49	3.32
Holiday	LasPalmas	4.16	0	0	0	0	0.51	0.39	0.29	0.23
Victorville	LasPiedras	4.16	0.54	0	0	0	0.67	0	0	0
San Gabriel	LasTunas	4.16	0.23	0	0	0	0.67	0	0	0
Palmdale	Lasker	12	1.86	1.86	1.86	1.86	2.63	2.54	2.01	1.71
Olympic	Lasky	4.16	0	0	0	0	1.26	0	0	0
Santa Monica	Lassen	4.16	1.01	0	0	0	0.81	0	0	0
Jefferson	Last	12	2.57	2.57	2.57	2.57	3.36	3.36	3.36	3.36
Randolph	Latchford	16	2.36	2.36	2.36	2.36	8.14	6.64	6.03	5.52
Industry	Lathe	12	0.91	0.91	0.91	0.91	3.48	3.48	3.48	3.48
Victor	Latimer	12	1.35	1.35	1.35	1.35	3.19	3.19	3.14	2.63
Repetto	Latin	4.16	0.95	0	0	0	0.7	0	0	0
Hanford	Laton	12	0	0	0	0	0	0	0	0
Coffee	Latte	12	0	0	0	0	3.49	0	0	0
Nelson	Lauda	33	16.12	16.12	16.12	8.38	0	0	0	0
Bolsa	Launch	12	3.02	3.02	3.02	0	3.29	3.29	3.29	3.05
Modoc	Lauro	4.16	0	0	0	0	1.14	0.72	0.57	0.48
West Barstow	Lauterbach	4.16	0	0	0	0	0	0	0	0
Amboy	Lava	12	0.96	0	0	0	3.49	3.49	3.27	2.45
Wimbledon	Laver	12	3.78	0	0	0	3.49	0	0	0
Diamond Bar	Lawman	12	0	0	0	0	3.09	3.09	3.09	2.76
Fullerton	Lawrence	12	1.6	0	0	0	3.48	0	0	0
Stadium	Laws	12	2.9	2.9	2.9	2.9	3.44	3.44	3.44	3.33
Puente	Lawson	12	0.29	0.29	0.29	0.29	3.49	3.49	3.49	3.49
Pechanga	Lazaro	12	1.18	1.18	1.18	1.18	2.46	2.46	2.46	2.13
Limestone	Lead	12	0.22	0	0	0	2.43	2.43	2.16	1.82
Dunes	Leak	12	3.02	3.02	3.02	3.02	3.09	2.08	1.96	1.39
Stetson	Lear	12	1.2	1.2	1.2	1.2	3.38	3.38	3.38	3.38
Mt. Vernon	Leber	4.16	1.01	0	0	0	0.81	0	0	0
Borrego	Leche	12	1.9	1.9	1.9	1.9	3.43	3.43	3.3	2.77
Palmdale	Ledford	12	0	0	0	0	3.3	3.3	3.3	3.01
Locust	Lee	4.16	0.54	0	0	0	0.97	0	0	0
Bassett	Leetum	12	0	0	0	0	3.44	3.44	3.44	3.35
Santa Fe Springs	Leffingwell	12	1.11	1.11	1.11	1.11	3.3	3.3	3.3	3.02
Ventura	Legion	4.16	1.26	0	0	0	0.62	0	0	0
San Antonio	Lehigh	12	0.89	0.89	0.89	0.89	3.39	3.39	3.39	3.28
Shuttle	Leia	12	1.31	1.31	1.31	1.31	2.7	2.7	2.7	2.33
Locust	Lemon	4.16	0.8	0.8	0	0	1.23	0.81	0.56	0.47
Citrus	Lemonade	12	0.55	0.55	0.55	0.55	3.01	3.01	2.83	2.39
Carmenita	Lemont	12	3.02	0	0	0	3.49	0	0	0
Hanford	Lemoore	12	0	0	0	0	0	0	0	0
Cardiff	Lena	12	1.82	1.82	1.82	1.82	1.49	1.49	1.49	1.49
Rector	Leo	12	0	0	0	0	0	0	0	0
Auld	Leon	12	0.72	0.72	0.72	0.72	2.63	2.63	2.13	1.8
Anaverde	Leona	12	4.96	4.96	3.02	3.02	2.24	2.24	2.14	1.81
Amalia	Leonard	4.16	1.79	0	0	0	1.28	0.83	0.61	0.51
Lampson	Leopard	12	0.35	0.35	0.35	0.35	3.14	3.14	3.14	3.14
Fruitland	Leota	16	3.97	3.97	3.97	3.97	9.08	7.54	6.8	6.32
Valencia	Leroy	4.16	0.27	0	0	0	0.6	0	0	0

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Bedford	Leslie	4.16	0	0	0	0	1.13	0.78	0.6	0.48
Newbury	Lesser	16	1.31	0	0	0	7.42	0	0	0
Jefferson	Lester	12	0	0	0	0	3.12	2.77	2.15	1.83
Blythe City	Lettuce	12	2.31	2.31	2.31	2.31	3.07	3.07	3.07	2.66
Monolith	Leveche	12	1.54	1.54	1.54	1.54	3.31	3.31	2.45	2.08
Industry	Level	12	1.36	1.36	1.36	1.36	2.85	2.85	2.85	2.6
Lindsay	Lewis	12	0	0	0	0	0	0	0	0
Pierpont	Lexington	4.16	1.01	1.01	0	0	0.78	0.78	0.6	0.5
Sepulveda	Liberator	16	0.88	0.88	0.88	0.88	9.04	7.28	6.58	6.08
Cudahy	Liberty	4.16	0.3	0.3	0.3	0.3	1.26	0.9	0.68	0.57
Repetto	Libra	16	1.84	1.84	1.84	1.84	13.12	7.13	6.45	5.98
Inglewood	Lidums	4.16	0.27	0.27	0.27	0.27	1.15	0.74	0.6	0.48
North Intake	Lift	12	1.43	0	0	0	3.49	0	0	0
Rolling Hills	Lilac	4.16	0.87	0	0	0	0.58	0	0	0
Daisy	Lily	4.16	1.01	0	0	0	1	0	0	0
Sierra Madre	Lima	4.16	0	0	0	0	1.1	0.57	0.57	0.48
Live Oak	Limber	12	2.32	2.32	2.32	2.32	2.72	2.72	2.72	2.35
Locust	Lime	4.16	0.11	0.11	0.11	0.11	0.74	0.74	0.56	0.47
Layfair	Liming	12	1.34	1.34	1.34	1.34	3.36	3.36	3.36	3.36
Elsinore	Limited	12	3.02	3.02	3.02	3.02	3.26	3.26	2.99	2.42
Calectric	Limonite	33	7.77	7.77	7.77	7.77	11	11	7.09	5.62
Visalia	Lincoln	4.16	0	0	0	0	0	0	0	0
Garnet	LindaVista	12	0.49	0.49	0.49	0.49	2.92	2.6	2.07	1.75
Stetson	Lindberg	12	0	0	0	0	3.04	3.04	3.01	2.55
Laurel	Linder	12	0	0	0	0	0	0	0	0
Malibu	Lindero	16	1.74	1.74	1.74	1.74	7.08	5.9	5.33	4.95
Stadler	Linebacker	12	0	0	0	0	3.38	3.38	3.38	3.1
Rector	Linnell	12	0	0	0	0	0	0	0	0
Wrightwood	Linnet	2.4	0.25	0	0	0	0.71	0	0	0
Santiago	Lire	12	0	0	0	0	1.77	1.77	1.77	1.5
La Veta	LisaAnne	12	0	0	0	0	2.93	2.93	2.89	2.44
Bryan	Lisbon	12	2.58	0	0	0	3.39	0	0	0
Chase	Liston	12	1.26	1.26	1.26	1.26	2.31	2.31	2.31	2.31
Limestone	Lithium	12	2.5	2.5	2.5	2.5	2.57	2.57	2.57	2.57
Valencia	Litra	4.16	0.27	0.27	0.27	0.27	0.94	0.63	0.53	0.41
Calectric	LittleMountain	33	0	0	0	0	27	27	27	22.34
Lafayette	Littler	12	3.02	0	0	0	3.49	0	0	0
Valley	Livermore	12	1.58	1.58	1.58	1.58	2.04	2.04	2.04	1.7
Madrid	Llewellyn	4.16	0.46	0	0	0	0.6	0	0	0
Del Sur	Lloyd	12	0.39	0.39	0.39	0.39	0	0	0	0
Cornuta	Lobby	12	2.1	2.1	2.1	2.1	3.43	3.43	3.43	3.22
Chino	Lobet	12	0	0	0	0	3.43	3.43	3.43	3.27
Pechanga	Lobo	12	0	0	0	0	2	1.9	1.37	1.15
Beverly	Local	16	0.96	0.96	0.96	0.96	8.22	6.92	6.43	5.7
Lennox	Lock	4.16	0.04	0	0	0	0.72	0	0	0
Kramer	Lockhart	33	0	0	0	0	0	0	0	0
Nelson	Lockner	12	1.7	1.7	1.7	1.7	3.22	3.22	2.94	2.46
Ravendale	Locksley	16	4.68	3.94	3.94	3.94	8.41	6.8	6.1	5.67
Railroad	Locomotive	12	0	0	0	0	3.36	3.36	3.36	3.36
Rush	Lodestar	16	7.5	0	0	0	7.43	0	0	0
Carmenita	Loftus	12	0	0	0	0	0	0	0	0
White Mt.	LogCabin	2.4	0	0	0	0	0	0	0	0
Earlimart	Logan	12	0	0	0	0	0	0	0	0
La Veta	Lola	12	0	0	0	0	2.87	2.87	2.87	2.84
Moraga	Lolita	12	3.02	3.02	3.02	3.02	3.34	3.34	3.34	3.34
Mesa	Lomas	16	5.01	5.01	3.97	3.97	8.69	7.3	6.58	6.11
Movie	Lombard	16	7.61	3.97	3.97	3.97	8.32	7	6.34	5.84
San Marino	Lombardy	4.16	0.52	0.52	0.52	0.52	1.16	0.63	0.47	0.4
Rolling Hills	Lomita	16	0.77	0.77	0.77	0.77	8.47	7.02	6.14	5.69
Las Lomas	London	12	0	0	0	0	2.34	2.34	2.28	1.86
Long P.T.	Long	4.16	0.45	0	0	0	1.29	0	0	0
Bovine	Longhorn	12	0	0	0	0	3.26	3.26	3.26	3.26
State Street	Loop	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.35
Rialto	Loper	4.16	0	0	0	0	0.66	0	0	0
San Fernando	Lopez	16	0.28	0.28	0.28	0.28	5.15	4.3	3.86	3.57
Torrance	Loquat	16	3.97	3.97	3.94	3.94	7.8	6.66	5.88	5.46
Savage	Lorene	12	1.69	0	0	0	3.32	0	0	0
Naples	Loreta	4.16	0.63	0.63	0.63	0.63	1.16	0.76	0.58	0.48
Jefferson	Lorna	12	0.88	0.88	0.88	0.88	2.67	2.67	2.67	2.67
Isla Vista	LosCarneros	16	10.06	10.06	10.06	10.06	5.6	4.85	4.25	3.94
Phelan	Lotto	12	2.79	2.79	2.79	2.79	0	0	0	0
Barre	Lotus	12	2.9	2.9	2.9	2.9	3.44	3.44	3.44	3.17
Rialto	Love	4.16	0	0	0	0	0.71	0	0	0
Sierra Madre	Lowell	4.16	0	0	0	0	1.18	0.72	0.56	0.47
Oak Grove	Lowry	12	0	0	0	0	0	0	0	0
Piute	Lucerne	12	2.92	2.92	2.92	2.92	3	2.02	1.6	1.34
Broadway	Lucia	12	3.02	3.02	3.02	3	3.46	3.46	3.46	3.46
Beverly	Luckman	16	0	0	0	0	8.89	7.11	6.53	5.92
Redlands	Lugonia	12	2.5	2.5	2.5	2.5	3.44	3.44	3.44	3.44
Pechanga	Luiseno	33	8.38	8.38	8.38	8.38	27	16.71	12.56	9.56

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Potrero	Luna	16	5.91	3.97	3.97	3.97	7.66	6.3	5.61	5.21
Oasis	Lupine	12	5.94	3.46	3.02	3	1.26	1.26	1.25	1.05
Oldfield	Luray	4.16	0	0	0	0	0.65	0	0	0
Luring P.T.	Luring	2.4	0.13	0	0	0	0.82	0	0	0
Newcomb	Lusk	12	0	0	0	0	2.08	2.08	2.08	1.85
Bixby	Luther	4.16	0.55	0	0	0	0.89	0	0	0
Imperial	Luxor	12	3.07	3.07	3.07	3.02	3.49	3.49	3.49	3.49
Gale	Luz	33	0	0	0	0	0	0	0	0
Ellis	Lyell	12	3.02	3.02	3.02	3.02	3.17	3.17	3.17	3.17
Lynwood	Lyndora	4.16	0.56	0.56	0.56	0.56	1.27	0.82	0.65	0.55
Lark Ellen	Lynne	12	0	0	0	0	3.33	3.33	3.33	3.33
Lampson	Lynx	12	3.02	0	0	0	3.49	0	0	0
Newhall	Lyons	16	0	0	0	0	7.46	5.99	5.42	5.02
Alder	Lytle	12	0	0	0	0	0	0	0	0
Sunny Dunes	Lytton	4.16	0	0	0	0	0.63	0	0	0
Culver	M.G.M.	16	1.07	1.07	1.07	1.07	9.76	7.9	6.93	6.41
Cudahy	Maas	4.16	0.33	0.33	0.33	0.33	1.27	0.71	0.56	0.47
La Veta	Mable	12	1.63	1.63	1.63	1.63	3.45	3.45	3.45	3.45
Chestnut	Macadamia	12	2.57	2.57	2.57	2.57	0	0	0	0
Industry	Machine	12	2.91	2.91	2.91	2.91	3.19	3.19	3.19	3.18
Borrego	Macho	12	3.66	3.02	3.02	3.02	3.35	3.35	3.35	3.35
Soquel	Maciel	12	2.04	2.04	2.04	2.04	3.06	3.06	3.05	2.47
Roadway	Mack	12	3.02	3.02	3.02	3	3.45	3.45	3.17	2.66
Tipton	Macomber	12	0	0	0	0	0	0	0	0
Muscoy	Macy	4.16	0.43	0.43	0.43	0.43	1.06	0.71	0.56	0.47
Walteria	Madera	4.16	0	0	0	0	1.2	0.44	0.44	0.37
Colorado	Madison	16	0	0	0	0	10.06	7.78	7.01	6.5
Madrone P.T.	Madrone	4.16	0	0	0	0	0.83	0	0	0
Irvine	Magazine	12	2.52	2.52	2.52	2.52	3.32	3.32	3.32	3.32
Orange	Magenta	12	0.64	0.64	0.64	0.64	3.46	3.46	3.46	3.46
Saugus	Magic	16	0	0	0	0	12.29	7.56	6.97	6.34
Bedford	Magnetic	4.16	0	0	0	0	0.74	0	0	0
Chase	Magnolia	12	0.16	0.16	0.16	0.16	3.1	3.1	3.1	2.94
Etiwanda	Magoo	12	0.34	0.34	0.34	0.34	2.59	1.67	1.67	1.41
Victor	Magua	12	0	0	0	0	3.37	3.37	3.37	3.37
Latigo	Maguire	16	4.92	3.97	3.97	3.97	4.95	4.15	3.73	3.47
Maiden P.T.	Maiden	4.16	0.17	0	0	0	1.03	0	0	0
Edinger	MainSt.	4.16	0.46	0	0	0	0.75	0	0	0
Ontario	Maitland	4.16	0.47	0	0	0	0.78	0	0	0
Soquel	Maize	12	2.98	2.98	2.98	2.98	2.77	2.77	2.27	1.78
Palos Verdes	Major	4.16	0.42	0	0	0	0.79	0	0	0
Palos Verdes	MalagaCove	4.16	0	0	0	0	0.93	0.56	0.49	0.37
Vail	Malden	16	0.47	0.47	0.47	0.47	7.5	6.26	5.66	5.25
Railroad	Mallet	12	0	0	0	0	3.12	3.12	2.69	2.23
Saticoy	Maloy	16	3.65	3.65	3.65	3.65	6.78	5.57	5.03	4.67
Laguna Bell	Malt	16	3.97	0	0	0	7.31	0	0	0
North Oaks	Mamba	16	0.13	0.13	0.13	0	3.9	3.25	2.96	2.72
Minaret	Mamie	12	0	0	0	0	0	0	0	0
Morningside	Manchester	4.16	0.12	0	0	0	0.85	0	0	0
Citrus	Mandarin	12	0.03	0.03	0.03	0.03	3.13	3.13	2.77	2.29
Limestone	Manganese	12	0	0	0	0	3.37	3.37	3.37	2.63
Flanco	Mango	4.16	0.2	0.2	0.2	0.2	0.99	0.64	0.51	0.43
Lafayette	Mangrum	12	6.06	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Hathaway	Manila	4.16	0.23	0	0	0	0.62	0	0	0
Indian Wells	Manitou	12	0	0	0	0	0	0	0	0
Declez	Manning	12	3.19	3.19	3.19	3.02	3.43	3.43	3.43	3.43
Anita	Manor	4.16	0	0	0	0	1.05	0.67	0.51	0.43
Randall	Manteca	12	0.21	0.21	0.21	0.21	2.89	2.89	2.89	2.76
Haveda	Manuel	4.16	0.09	0.09	0.09	0.09	1.14	0.86	0.59	0.49
Cameron	Manville	12	3.02	0	0	0	3.49	0	0	0
Goshen	Manzanillo	12	0	0	0	0	0	0	0	0
Victor	Manzer	12	0	0	0	0	0	0	0	0
Eric	Mapes	12	0	0	0	0	3.33	3.33	3.33	3.32
Beverly	Maple	4.16	0	0	0	0	0.96	0.61	0.5	0.4
Somerset	Maplewood	12	1.57	1.57	1.57	1.57	3.48	3.48	3.48	3.48
Culver	MarVista	16	5.97	3.97	3.97	3.97	7.54	6.3	5.64	5.24
Borrego	Maraca	12	0	0	0	0	3.48	3.48	3.11	2.62
Mascot	Marauder	12	0	0	0	0	0	0	0	0
Declez	Marble	12	3	3	3	3	3.45	3.45	3.45	3.15
Francis	Marbuck	12	0	0	0	0	3.23	3.23	3.23	3.15
Madrid	Marcellina	4.16	1.01	0	0	0	0.89	0	0	0
Padua	Marconi	12	0	0	0	0	3.44	3.44	3.44	3.17
Haskell	Marcus	16	2.17	2.17	2.17	2.17	5.21	4.12	3.75	3.45
Atwood	Marda	12	4.11	3.02	3.02	3	3.34	3.34	3.34	3.34
Arcadia	Marendale	16	2.17	2.17	2.17	2.17	9.68	8.02	7.15	6.61
Alhambra	Marengo	4.16	0.04	0.04	0.04	0.04	1.23	0.83	0.63	0.53
Felton	Margaret	16	3.84	3.84	3.84	3.84	8.45	6.74	6.06	5.63
Alhambra	Marguerita	16	5.02	3.97	3.97	3.97	10.47	7.85	7.16	6.53
Rancho	Marianna	12	3.02	3.02	3	3	2.88	2.88	2.88	2.56
Barre	Marigold	12	1.85	1.85	1.85	1.85	3.45	3.45	3.45	3.45

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Marina P.T.	Marina	4.16	0.22	0	0	0	0.68	0	0	0
Palmdale	Mark	12	1.83	1.83	1.83	1.83	3.22	3.22	3.22	3.22
Oldfield	Market	4.16	0	0	0	0	0.7	0	0	0
Cima	Marl	16	0.16	0.16	0.16	0.16	6.46	4.48	3.87	3.31
Hathaway	Marland	12	0	0	0	0	3.45	3.45	3.45	3.45
Culver	Marlene	16	7.18	7.18	7.18	7.18	9.04	6.78	6.78	6.26
Thornhill	Marquis	12	3	0	0	0	3.49	0	0	0
Cabrillo	Marriott	12	0.37	0.37	0.37	0.37	3.49	3.49	3.49	3.49
Bowl	Mars	12	3.02	3.02	3.02	3.02	3.41	3.41	3.41	3.41
Earlimart	Marsh	12	0	0	0	0	0	0	0	0
Marine	Marshall	16	0.78	0.78	0.78	0.78	7.68	6.42	5.76	5.35
Artesia	Martha	4.16	0.26	0	0	0	0.93	0	0	0
Davidson City	Martin	4.16	0.11	0	0	0	0.63	0	0	0
Chiquita	Martini	12	0.58	0.58	0.58	0.58	3.07	3.07	3.07	2.65
Somerset	Marty	12	0	0	0	0	3.43	3.43	3.43	3.43
Nelson	Marvin	33	9.83	9.83	9.83	8.38	27	27	27	27
Etiwanda	Marx	12	1.4	1.4	1.4	1.4	2.4	1.77	1.77	1.5
La Veta	Mary	12	2.36	2.36	2.36	2.36	3.34	3.34	3.34	3.34
Carolina	Maryland	12	1.9	1.9	1.9	1.9	3.4	3.4	3.4	3.4
Gilbert	Mashie	12	3.02	3.02	3.02	3.02	3.42	3.42	3.42	3.42
Carolina	Massachusetts	12	0	0	0	0	3.17	3.17	3.17	3.17
Nelson	Massacre	12	0.6	0.6	0.6	0.6	1.89	1.89	1.89	1.73
Harding	Masser	4.16	0	0	0	0	1.26	0.6	0.6	0.5
Pico	Mast	12	5.44	3	3	3	3.14	3.14	3.14	2.89
Concho	Matador	12	0	0	0	0	0	0	0	0
Pechanga	Matera	12	1	1	1	1	2.05	2.05	2.05	1.76
Pepper	Mateus	12	3.02	3.02	3.02	3.02	3.45	3.45	3.45	3.45
Tulare	Mathias	12	0	0	0	0	0	0	0	0
Ojai	Matilija	16	1.58	1.58	1.58	1.58	7.45	6.24	5.63	5.23
Fullerton	Matlock	12	3.02	3.02	3.02	3.02	3.33	3.33	3.33	3
Oldfield	Matney	4.16	0.66	0.66	0.66	0.66	1.21	0.9	0.57	0.48
Barstow	Mauel	12	0	0	0	0	0	0	0	0
Gonzales	Maulhardt	16	3	3	3	3	6.71	5.43	4.91	4.53
Savage	MaunaLoa	12	4.83	4.83	3.78	3.02	3.4	3.4	2.79	2.33
Wilsona	Maverick	12	1.47	1.47	1.47	1.47	3.07	2.38	1.9	1.6
Coffee	Maxim	12	3.02	3.02	3.02	3.02	1.07	1.02	0.84	0.68
Haskell	Maximus	16	0.9	0.9	0.9	0.9	6.73	4.97	4.44	4.06
Rivera	Maxine	4.16	0.37	0.37	0.37	0.37	0.96	0.73	0.54	0.43
Saticoy	Maxson	16	2.83	2.83	2.83	2.83	6.16	5.12	4.64	4.29
Indian Wells	Mayan	12	0	0	0	0	0	0	0	0
Cortez	Maybell	12	0	0	0	0	3.11	3.11	3.11	2.76
Elsinore	Mayer	33	8.38	8.38	8.38	8.38	27	17.44	15.42	9.87
Ramona	Mayfair	4.16	0	0	0	0	1.2	0.85	0.67	0.56
Sharon	Mayfield	4.16	0.32	0.32	0.32	0.32	1.11	0.67	0.52	0.44
Bullis	Mayo	16	2.99	2.99	2.99	2.99	7.93	6.29	5.8	5.28
Lancaster	Mays	12	5.88	3.02	3.02	3.02	3.24	3.24	3.24	3.24
Brea	Mazatlan	12	0.21	0.21	0.21	0.21	2.93	2.93	2.93	2.93
El Sobrante	McAllister	12	0	0	0	0	2.81	2.81	2.81	2.36
Amargo	McCaslin	4.16	0	0	0	0	0	0	0	0
Mc Clary P.T.	McClary	4.16	0.89	0.89	0.89	0.89	0.86	0.51	0.42	0.34
Cabrillo	McCormick	12	7.14	0	0	0	3.49	0	0	0
Blythe City	McCoy	33	16.17	8.38	8.38	0	0	0	0	0
Wimbledon	McEnroe	12	0	0	0	0	0	0	0	0
Newcomb	McLaughlin	12	0	0	0	0	2.75	2.75	2.75	2.52
Newhall	Mcbean	16	0	0	0	0	8.2	5.92	5.34	4.96
Belding	Mccallum	4.16	0	0	0	0	0.57	0	0	0
Beverly	Mccarty	16	0	0	0	0	9.43	7.78	6.91	6.38
Jersey	Mccloud	16	5.64	3.97	3.97	3.97	6.65	5.53	5.11	4.63
Browning	Mcclure	12	0	0	0	0	0	0	0	0
Lennox	Mcdonnell	16	3.97	3.97	3.97	3.97	8.19	6.9	6.2	5.76
Marine	Mcewan	16	5.52	0	0	0	7.26	0	0	0
Browning	Mcfarland	12	0	0	0	0	0	0	0	0
Sherwin	Mcgee	12	0	0	0	0	0	0	0	0
Brookhurst	Mckeever	12	0.03	0.03	0.03	0.03	3.41	3.41	3.41	3.41
Mckevett P.T.	Mckevett	4.16	0.16	0	0	0	0.85	0	0	0
Fremont	Mckinley	4.16	0.9	0.9	0.9	0.9	1.26	0.73	0.58	0.48
Thornhill	Mcmanus	12	0.13	0.13	0.13	0.13	2.87	2.87	2.87	2.87
Lucas	Mcnab	4.16	0.05	0	0	0	0.85	0	0	0
Cardiff	Meadowbrook	12	2.47	2.47	2.47	2.47	3.42	3.42	3.42	3.16
Wrightwood	Meadowlark	12	3.02	0	0	0	3.49	0	0	0
El Porto	Meadows	4.16	0	0	0	0	0.77	0	0	0
Upland	Meagan	12	0	0	0	0	3.44	3.44	3.44	3.44
Beverly	Meander	16	3.2	3.2	3.2	3.2	10.71	7.09	6.41	5.94
Cucamonga	Mears	12	0	0	0	0	2.36	2.36	2.36	2.09
Villa Park	Meats	12	0.7	0.7	0.7	0.7	2.74	2.74	2.74	2.74
Trophy	Medal	12	0	0	0	0	2.79	2.57	2.01	1.71
Lancaster	Medallion	12	4.86	3.02	3.02	3.02	2.51	2.51	2.51	2.51
Terrace	Medford	4.16	0.08	0.08	0.08	0.08	0.93	0.62	0.49	0.41
Colorado	Medical	4.16	0.3	0.3	0.3	0.3	0.81	0.53	0.42	0.35
Bixby	Medio	4.16	0.27	0	0	0	0.76	0	0	0

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Bicknell	Mednick	4.16	1.01	0	0	0	0.88	0	0	0
San Bernardino	Medusa	12	0	0	0	0	3.29	3.29	3.27	2.7
O'neill	Melinda	12	1.67	1.67	1.67	1.67	3.18	3.18	3.18	3.15
La Veta	Melissa	12	2.07	2.07	2.07	2.07	3.41	3.41	3.41	3.41
Hi Desert	Melody	25	2.15	2.15	2.15	2.15	1.31	1.31	1.31	1.31
Blythe City	Melon	12	1.28	1.28	1.28	1.28	3.21	3.21	3.21	3.21
Hemet	Melvere	12	0.22	0	0	0	3.15	0	0	0
La Habra	Memory	12	0.46	0.46	0.46	0.46	3.29	3.29	3.29	3.29
Tennessee	Memphis	12	0.17	0.17	0.17	0.17	2.46	2.46	2.34	1.98
Newcomb	Menifee	12	0.81	0.81	0.81	0.81	1.78	1.48	1.19	0.99
Yukon	Menlo	4.16	0.86	0	0	0	0.61	0	0	0
Newhall	Mentry	16	4.03	4.03	3.94	3.94	7.59	6.16	5.54	5.12
Telegraph	Mercado	12	1.4	1.4	1.4	1.4	3.3	3.3	3.3	3.17
Inglewood	Mercantile	4.16	1.26	0	0	0	0.77	0	0	0
Vera	Mercedes	12	0.55	0.55	0.55	0.55	3.22	3.22	3.22	3.03
Newmark	Mercer	16	0	0	0	0	7.91	6.65	5.98	5.56
Calectric	Meredith	33	8.38	8.38	0	0	25.94	25.94	24.44	18.3
Anita	Meridian	16	1.04	1.04	1.04	1.04	9.71	7.2	6.5	6.03
Latigo	Merlin	16	3.97	3.97	3.97	3.94	6.6	5.49	4.94	4.59
Pauba	Merlot	12	3.11	3.11	3.11	3.02	2.77	2.11	2.11	1.74
Flanco	Merril	4.16	0.19	0.19	0.19	0.19	1.23	0.63	0.53	0.42
Poplar	Merrit	12	0	0	0	0	0	0	0	0
Venida	Merryman	12	0	0	0	0	0	0	0	0
Amador	Mervin	4.16	0	0	0	0	0.63	0.63	0.5	0.42
Yucaipa	MesaGrande	12	3.02	3.02	3.02	3.02	3.31	3.31	3.31	3.31
Milliken	Mescal	12	0	0	0	0	0	0	0	0
Culver	Mesmer	4.16	0.78	0.78	0.78	0.78	1.09	0.47	0.47	0.39
Hesperia	Mesquite	12	0.22	0.22	0.22	0.22	2.45	2.45	2.09	1.73
Gisler	Meteor	12	1.58	0	0	0	3.46	3.46	3.46	3.46
Upland	Metro	12	0.15	0.15	0.15	0.15	3.26	3.26	3.26	3.14
Cummings	Mettler	12	0	0	0	0	1.87	1.28	0.99	0.84
Clark	Metz	4.16	0	0	0	0	1	0.5	0.5	0.42
Ely	Mexico	12	0.58	0.58	0.58	0.58	3.29	3.29	3.29	3.29
Sullivan	Miami	4.16	0.24	0	0	0	0.97	0.64	0.51	0.42
Crest	Mica	16	7.92	7.92	7.92	7.92	8.57	7.01	6.35	5.85
Corona	Michael	12	0	0	0	0	3.48	3.48	3.48	3.09
Cortez	Michelle	12	2.98	2.98	2.98	2.98	3.41	3.41	3.41	2.97
Signal Hill	Michigan	4.16	0	0	0	0	0.58	0	0	0
Line Creek	Micro	4.16	0	0	0	0	0	0	0	0
Liberty	MidValle	12	0	0	0	0	0	0	0	0
Saticoy	MiddleRoad	16	3.11	3.11	3.11	3.11	3.61	3	2.71	2.52
Lafayette	Middlecoff	12	2.07	2.07	2.07	2.07	3.43	3.43	3.24	2.61
Quinn	Midge	12	0	0	0	0	0	0	0	0
Milliken	Midori	12	4.31	3.02	3	3	3.48	3.48	3.48	2.94
Cedarwood	Midway	4.16	1	0	0	0	0.85	0	0	0
Ramona	Midwick	4.16	0.15	0.15	0.15	0.15	1.27	0.78	0.62	0.52
Alon	Miguel	12	3	0	0	0	3.49	0	0	0
Marion	Mildred	12	0	0	0	0	3.25	0	0	0
Trophy	Miler	12	0	0	0	0	3.4	3.4	3.4	3.4
Huntington Park	Miles	4.16	0.62	0.62	0.62	0.62	1.29	0.83	0.65	0.54
Tulare	Milk	12	0	0	0	0	0	0	0	0
Santa Fe Springs	Mill	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Nogales	Millennium	12	0.09	0.09	0.09	0.09	2.96	2.96	2.52	2.07
Walteria	Miller	4.16	0.42	0	0	0	0.82	0	0	0
Passons	Millergrove	12	0	0	0	0	3.38	3.38	3.38	3.07
Alon	Millpoint	12	2.54	2.54	2.54	2.54	3.46	3.46	3.46	3.46
Valdez	Milo	16	0.86	0.86	0.86	0.86	6.48	5.53	4.75	4.41
Santa Barbara	Milpas	16	0.88	0.88	0.88	0.88	7.4	6.18	5.58	5.18
Tamarisk	Mimosa	12	0	0	0	0	0	0	0	0
Visalia	Mineral	12	0	0	0	0	0	0	0	0
Savage	Mingo	12	0.66	0.66	0.66	0.66	0	0	0	0
Carolina	Minnesota	12	0	0	0	0	3.26	3.26	3.26	3.26
El Nido	Minnow	16	3.91	3.91	3.91	3.91	9.29	7.55	6.69	6.17
Nelson	Minor	12	0	0	0	0	3.34	3.34	3.14	2.66
Crown	Minosa	12	1.72	0	0	0	3.4	3.4	3.4	3.4
San Bernardino	Minotaur	12	0	0	0	0	0	0	0	0
Saugus	MintCanyon	16	1.24	1.24	1.24	1.24	6.35	6.35	5.72	5.25
Liberty	Minuteman	12	0	0	0	0	0	0	0	0
Carmenita	Mira	12	3.02	3.02	3.02	3.02	3.46	3.46	3.46	3.46
Ridgecrest	MiracleCity	4.8	0	0	0	0	0	0	0	0
Rolling Hills	Miralesta	16	6.3	6.3	3.97	3.97	7.21	7.21	6.56	6.03
Montecito	Miramar	4.16	0.25	0.25	0	0	1.2	0.94	0.63	0.52
Huntington Park	Miramonte	4.16	0.7	0	0	0	0.61	0	0	0
Savage	Mirror	12	2.54	2.54	2.54	2.54	3.21	3.21	3.12	2.51
San Fernando	Mission	16	1.14	1.14	1.14	1.14	5.93	5.03	4.41	4.09
Riverway	Mississippi	12	0	0	0	0	0	0	0	0
South Gate	Missouri	4.16	1.57	1.57	1.01	1.01	1.27	0.9	0.6	0.51
Capitan	Mist	16	10.31	3.97	3.97	3.97	0	0	0	0
Tamarisk	Mistletoe	12	0	0	0	0	0	0	0	0
Seabright	Mitchell	12	3.02	3.02	3.02	3	3.49	3.49	3.49	3.49

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Moab P.T.	Moab	4.16	0.92	0	0	0	1.24	0	0	0
North Oaks	Moccasin	16	0.6	0.6	0.6	0.6	6.2	5.16	4.66	4.33
Mockingbird P.T.	Mockingbird	12	1.7	0	0	0	3.49	0	0	0
Jefferson	Modelo	12	0	0	0	0	2.77	2.77	2.73	2.31
O'neill	Modjeska	12	1.73	1.73	1.73	1.73	3.02	3.02	2.97	2.51
Lemon Cove	Moffitt	12	0	0	0	0	0	0	0	0
Sierra Madre	Mohawk	4.16	0.02	0	0	0	0.63	0	0	0
Indian Wells	Mohican	12	0	0	0	0	0	0	0	0
Pico	Mole	12	5.83	0	0	0	3.49	0	0	0
Hathaway	Molino	12	2.88	2.88	2.88	2.88	3.49	3.49	3.49	3.49
Athens	Mona	4.16	1.06	1.01	1.01	1.01	1.29	0.78	0.58	0.49
Porterville	Monache	12	0	0	0	0	0	0	0	0
Royal	Monarch	16	3.45	3.45	3.45	3.45	9.05	7.2	6.52	6.04
Santiago	Money	12	0	0	0	0	3.49	3.49	2.62	2.62
Johanna	Monopoly	12	0.8	0.8	0.8	0.8	3.49	3.49	3.49	3.49
Woodville	Monroe	12	0	0	0	0	0	0	0	0
Oak Grove	Monson	12	0	0	0	0	0	0	0	0
Yorba Linda	Monsoon	12	0	0	0	0	3.43	3.43	3.43	3.14
Signal Hill	Montana	12	3	0	0	0	3.44	0	0	0
Barstow	Montara	33	0	0	0	0	0	0	0	0
San Antonio	Montclair	12	3.02	0	0	0	3.28	0	0	0
Royal	Montgomery	16	1.36	1.36	1.36	1.36	7.92	6.53	5.89	5.47
Canadian P.T.	Montreal	12	3.86	3.02	3.02	3.02	3.46	3.46	3.46	2.96
La Canada	Montrose	4.16	0	0	0	0	1.24	0.85	0.57	0.47
Cardiff	Monty	12	3.9	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Joshua Tree	Monument	12	3.46	3.46	3.46	3.46	3.3	3.3	3.3	3.3
Carmenita	Moody	12	3.64	3.64	3.64	3.64	1.49	1.49	1.49	1.49
Walteria	Moon	4.16	0.09	0.09	0.09	0.09	1.23	0.84	0.66	0.55
Repetto	Moonbeam	4.16	0	0	0	0	1.21	0.62	0.62	0.52
Quartz Hill	Moonglow	12	3.24	3.24	3.24	3.24	2.6	2.6	2.6	2.6
Gisler	Moonwalk	12	0.02	0.02	0.02	0.02	3.23	3.23	3.23	3.07
Fruitland	Moore	4.16	0.49	0.49	0.49	0.49	1.24	0.9	0.61	0.49
Randall	Mora	12	0	0	0	0	2.4	1.66	1.33	1.12
Layfair	Moran	12	0	0	0	0	3.32	3.32	3.32	3.32
Santa Susana	Moreland	16	0	0	0	0	6.72	5.48	4.94	4.58
Maraschino	Morello	12	9.17	3.02	3.02	3.02	3.49	3.49	3.49	3.05
Ditmar	Morgan	4.16	0.37	0	0	0	1.08	0.84	0.42	0.42
Moorpark	Morganstein	16	0	0	0	0	4.54	3.39	3.06	2.84
Huston	Moritz	12	1.41	1.41	1.41	1.41	3.47	3.47	2.9	2.46
Morongo P.T.	Morongo	12	4.83	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Saugus	Morrie	16	0.95	0.95	0.95	0.95	8.26	6.99	6.34	5.8
Auld	Morris	12	2.33	2.33	2.33	2.33	2.92	2.92	2.88	2.43
Ellis	Morrison	12	1.49	1.49	1.49	1.49	1.56	1.56	1.56	1.37
Cabrillo	Morse	12	0	0	0	0	3.34	3.34	2.43	2.05
Porterville	Morton	4.16	0	0	0	0	0	0	0	0
Narod	Mosebrook	12	1.93	1.93	1.93	1.93	3.39	3.39	3.39	3.39
Kimball	Mosquito	12	0	0	0	0	0	0	0	0
Dalton	Mossberg	12	3.02	0	0	0	3.49	0	0	0
Los Cerritos	Mossman	12	3.02	3.02	3.02	3	3.46	3.46	3.46	3.46
Lighthipe	Motz	12	2.46	2.46	2.46	2.46	3.49	3.49	3.49	3.49
Arro	Mountain	4.16	0	0	0	0	0.62	0	0	0
Windsor Hills	Mowder	4.16	0.85	0.85	0.85	0.85	1.16	0.6	0.48	0.4
Moynier P.T.	Moynier	4.16	0.91	0	0	0	1.03	0	0	0
Mt. Givens P.T.	Mt.Givens	2.4	0	0	0	0	0	0	0	0
Elsinore	Muddy	12	1.16	1.16	1.16	1.16	3.43	3.43	3.43	3.3
Sixteenth Street	Muffin	12	3.32	3.02	3.02	3.02	3.48	3.48	3.48	3.48
Colonia	Mugu	16	3.97	3.97	3.97	3.97	7.66	6.36	5.68	5.28
Irvine	Muirlands	12	0	0	0	0	3.22	3.22	2.82	2.34
Friendly Hills	Mulberry	4.16	0.58	0.58	0.58	0.58	1.26	0.84	0.68	0.54
Yermo	MuleCanyon	12	0	0	0	0	0	0	0	0
Fernwood	Mulford	16	4.36	0	0	0	11.21	0	0	0
Crater	Mulholland	16	3.97	3.97	3.97	3.97	6.04	5.1	4.58	4.25
Del Rosa	Mulkey	12	1.41	1.41	1.41	1.41	3.4	3.4	3.4	3.4
Murphy	Mulligan	12	8.17	0	0	0	3.48	0	0	0
Universal	Mummy	12	5.06	0	0	0	3.49	0	0	0
Longdon	Muriel	4.16	0.57	0	0	0	0.79	0	0	0
Redman	Muroc	12	3.02	3.02	3.02	3.02	2.86	2.27	1.68	1.23
Palm Canyon	Murray	12	2.71	2.71	2.71	2.71	3.16	3.16	3.16	3.16
Ivar	Muscatel	4.16	0.29	0.29	0.29	0.29	1.22	0.88	0.66	0.55
Timoteo	Muse	12	0.2	0.2	0.2	0.2	2.81	2.81	2.36	2
Piute	Museum	12	3.02	3.02	3.02	3.02	3.47	3.38	2.62	2.19
Pioneer	Musket	12	0	0	0	0	3.47	3.47	3.47	3.47
Hanford	Mussel	12	0	0	0	0	0	0	0	0
Isabella	Mustang	12	0	0	0	0	0	0	0	0
Redlands	Mutual	12	0	0	0	0	3.24	3.24	3.05	2.59
Ravendale	Myda	4.16	0.05	0	0	0	1.19	0.55	0.55	0.45
Irvine	Myford	12	2.09	2.09	2.09	2.09	3.16	3.16	3.16	2.84
Monrovia	Myrtle	4.16	0	0	0	0	1.19	0.69	0.53	0.45
Santa Fe Springs	Mystic	12	3.02	0	0	0	3.49	3.49	3.49	3.49
Graham	Nadeau	4.16	0.82	0.82	0.82	0.82	1.27	0.84	0.67	0.56

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Temple	Nadine	4.16	0	0	0	0	0.64	0	0	0
Doheny	Nadir	4.16	0.05	0.05	0.05	0.05	0.57	0.57	0.57	0.48
Alessandro	Nance	12	3.02	3.02	3.02	3.02	3.44	3.44	3.44	3.44
Stirrup	Nancy	4.16	0.35	0	0	0	1.07	0.58	0.46	0.38
Valley	Napa	12	1.58	1.58	1.58	1.58	3.25	3.25	3.18	2.7
Maraschino	Napoleon	12	1.35	1.35	1.35	1.35	2.81	2.81	2.49	2.07
Walteria	Narbonne	4.16	0	0	0	0	1.08	0.65	0.46	0.38
Daisy	Nardo	4.16	1.01	0	0	0	0.81	0	0	0
Shuttle	Nasa	12	0.97	0.97	0.97	0.97	2.69	2.69	2.53	2.13
Downey	Nash	4.16	0	0	0	0	1.02	0.61	0.48	0.4
Tennessee	Nashville	12	0	0	0	0	3.08	3.08	2.95	2.49
Bedford	Nason	4.16	0.31	0	0	0	0.65	0	0	0
Victor	Nassau	12	1.9	1.9	1.9	1.9	3.05	3.05	2.63	2.13
Wimbledon	Nastase	12	4.98	4.98	3.02	3.02	2.29	2.29	2.29	2.18
La Veta	Natalie	12	0.06	0.06	0.06	0.06	3.49	3.49	3.49	3.49
Cudahy	National	4.16	0.51	0.51	0.51	0.51	1.29	0.76	0.59	0.5
Valley	Nations	12	1.77	1.77	1.77	1.77	2.86	2.7	2.14	1.81
Levy	Naumann	16	3.97	3.97	3.97	3.97	6.5	5.47	4.92	4.58
Mentone	Navel	12	0	0	0	0	3.24	3.24	3.24	3.24
Hanford	Navigator	12	0	0	0	0	0	0	0	0
Marine	Navy	16	3.59	3.59	3.59	3.59	7.87	6.52	5.85	5.44
Rubidoux	Naylor	12	2.41	2.41	2.41	2.41	2.92	2.92	2.92	2.92
Newcomb	Neapolitan	12	0.59	0.59	0.59	0.59	2.09	2.09	1.64	1.39
Newhall	Neargate	16	1.51	1.51	1.51	1.51	5.85	4.67	4.22	3.92
South Gate	Nebraska	4.16	0.26	0.26	0.26	0.26	1.26	0.63	0.63	0.53
Friendly Hills	Nedra	4.16	0.2	0.2	0.2	0.2	0.52	0.52	0.52	0.43
Aqueduct	Needle	12	2.41	2.41	2.41	2.41	3.21	3.21	3.17	2.69
Somerset	Negel	4.16	0	0	0	0	1.18	0.86	0.65	0.52
Live Oak	Neibel	12	2.12	2.12	2.12	2.12	3.21	3.21	3.21	3.21
Blythe City	Neighbors	33	0	0	0	0	27	21.12	21.12	16.65
Santa Fe Springs	Nelles	12	0	0	0	0	3.48	3.48	3.48	3.48
Victoria	Nelson	16	3.43	3.43	3.43	3.43	8.34	6.71	6.05	5.62
Layfair	Nemaha	4.16	0.44	0.44	0.44	0.44	1.1	0.74	0.58	0.45
Marine	Neon	16	4.84	4.84	4.84	4.53	9.53	6.93	6.24	5.8
Modena	Nepal	12	1.18	0	0	0	3.11	0	0	0
Haskell	Nero	16	2.29	2.29	2.29	2.29	0	0	0	0
Fremont	Nestor	4.16	0.07	0.07	0.07	0.07	1.13	0.46	0.37	0.31
Sepulveda	Nevada	4.16	0.11	0	0	0	0.8	0.72	0.4	0.34
Jefferson	NewCastle	12	0	0	0	0	3.47	3.47	3.47	3.47
Allen	NewYork	4.16	0	0	0	0	1.18	0.55	0.55	0.46
Octol	Newman	12	0	0	0	0	0	0	0	0
Tapia	Nicholas	16	3.97	3.97	3.97	3.94	9.06	6.3	5.78	5.18
Limestone	Nickel	12	0.49	0.49	0.49	0.49	3.17	3.17	3.17	2.92
Rector	Nickerson	12	0	0	0	0	0	0	0	0
Randall	Nicklin	12	3.02	3.02	3.02	3	3.4	3.4	2.75	2.33
Highland	Nicole	12	3.02	3.02	3.02	3.02	3.36	3.36	3.36	3.36
Lockheed	Nighthawk	16	0	0	0	0	10.25	6.09	5.51	5.1
San Bernardino	Nike	12	2.55	2.55	2.55	2.55	3.37	3.37	3.37	3.05
Rio Hondo	Nile	12	0.5	0.5	0.5	0.5	3.16	3.16	3.16	3.16
Gisler	Nimbus	12	1.39	1.39	1.39	1.39	3.32	3.32	3.32	3.32
Sawtelle	Nimitz	16	4.96	0	0	0	5.01	0	0	0
Santa Monica	NinthSt	4.16	1.06	0	0	0	0.72	0	0	0
Mt. Pass A	Nipton	33	0	0	0	0	0	0	0	0
Inglewood	Nisley	16	8.69	3.97	3.97	3.97	9.17	7.91	6.95	6.43
Friendly Hills	Nixon	4.16	0	0	0	0	1.08	0.75	0.54	0.45
Sunnyside	NoAmerican	12	2.79	2.79	2.79	2.79	3.47	3.47	3.47	3.27
Manhattan	NoBeach	4.16	0.36	0.36	0.36	0	1.01	0.75	0.57	0.47
Woodville	Noakes	12	0	0	0	0	0	0	0	0
Pechanga	Noche	12	0	0	0	0	2.6	2.6	2.54	2.06
Ontario	Nocta	4.16	0	0	0	0	0.69	0	0	0
Ivar	Noel	4.16	0.17	0.17	0.17	0.17	1.22	0.66	0.57	0.44
Nogal P.T.	Nogal	4.16	0.13	0	0	0	1.08	0	0	0
Villa Park	Nohl	12	0	0	0	0	3.11	3.11	3.11	3.11
Colorado	Nomad	16	3.97	0	0	0	6.87	0	0	0
Firehouse	Nomex	12	0	0	0	0	3.43	3.43	3.43	3.02
Cypress	Nootka	12	0	0	0	0	3.32	3.32	3.32	3.32
Norco	Norconian	4.16	0.33	0	0	0	1.08	0	0	0
Skiland	Nordic	12	0	0	0	0	0	0	0	0
Costa Mesa	Nordina	4.16	0.45	0.45	0.45	0.45	1.08	0.66	0.51	0.43
Bowl	Norman	4.16	0.06	0.06	0.06	0.06	1.26	0.82	0.65	0.54
Howard	Normandie	4.16	0.14	0.14	0.14	0.14	1.03	0.85	0.53	0.44
Twentynine Palms	NorthAdobe	12	3.46	3.02	3.02	3.02	3	3	2.79	2.34
North Bay P.T.	NorthBay	2.4	0.06	0	0	0	0.69	0	0	0
Burnt Mill	NorthShore	12	2.64	2.64	2.64	2.64	3.49	3.49	3.49	3.27
Shandin	Northpark	12	0	0	0	0	2.99	2.36	1.87	1.59
Windsor Hills	Northridge	4.16	1.01	0	0	0	0.64	0	0	0
Ocean Park	Northside	4.16	0.11	0	0	0	0.65	0	0	0
Northstar P.T.	Northstar	12	1.61	0	0	0	3.49	0	0	0
Santa Fe Springs	Norton	12	2.64	2.64	2.64	2.64	3.27	3.27	3.27	3.27
Fairfax	Norwich	16	0.92	0.92	0.92	0.92	9.27	7.76	7	6.5

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Highland	Norwood	12	0.48	0.48	0.48	0.48	3.37	3.37	2.86	2.43
Valley	Nova	12	3.59	3.59	3.59	3.59	3.19	3.19	3.17	2.63
Firehouse	Nozzle	12	3.02	3.02	3.02	3.02	1.79	1.79	1.79	1.79
San Dimas	Nubia	12	0.93	0.93	0.93	0.93	3.37	3.37	3.37	2.84
Nursery P.T.	Nursery	4.16	0.37	0	0	0	1.1	0	0	0
Timoteo	Nurses	12	2.22	2.22	2.22	2.22	0	0	0	0
Indian Wells	Nusbaum	12	0	0	0	0	0	0	0	0
Tenaja	Nutmeg	12	3.46	3.02	3.02	3.02	3.08	3.08	3.08	3.08
Locust	Nylic	4.16	1.01	0	0	0	0.64	0	0	0
Murphy	O'Malley	12	2.82	2.82	2.82	2.82	3.44	3.44	3.44	3.44
Murphy	O'Toole	12	0	0	0	0	3.38	3.38	3.38	3.2
Montebello	Oak	4.16	0	0	0	0	0.75	0	0	0
Rosamond	OakCreek	12	3.02	3.02	3.02	3.02	3.38	2.49	2	1.68
Yucaipa	OakGlen	12	3.02	3	3	3	2.75	2.75	2.75	2.37
Oak Knoll P.T.	OakKnoll	2.4	0.54	0	0	0	0.91	0	0	0
Newcomb	Oakdale	12	1.74	1.74	1.74	1.74	3.1	3.1	2.96	2.49
Beverly	Oakhurst	4.16	0	0	0	0	1.24	0.66	0.66	0.55
Octol	Oakland	12	0	0	0	0	0	0	0	0
Arcadia	Oakwood	4.16	0	0	0	0	0.99	0.71	0.52	0.44
Lancaster	Oban	12	0	0	0	0	0	0	0	0
Elizabeth Lake	Oboe	16	0.19	0.19	0.19	0.19	4.33	3.6	3.23	3
Limestone	Obsidian	12	0.73	0.73	0.73	0.73	3.25	3.25	3.25	3.25
Cherry	Ocana	12	4.3	4.3	4.3	3	3.49	3.49	3.49	3.49
La Fresa	Occidental	16	10.84	3.97	3.97	3.97	8.86	7.65	6.68	6.2
Seabright	Ocean	12	3.02	0	0	0	3.49	0	0	0
Locust	Oceanic	4.16	0.39	0	0	0	0.7	0	0	0
Yukon	Octane	16	5.11	3.97	3.97	3.97	7.9	6.59	5.95	5.52
Washington	Offside	12	0	0	0	0	3.47	3.47	3.47	3.47
Costa Mesa	Ogle	4.16	0.75	0.75	0.75	0.75	1.2	0.67	0.53	0.45
Bowl	Ohio	4.16	0.55	0	0	0	0.77	0	0	0
Santa Fe Springs	Oil	12	0	0	0	0	3.27	3.27	3.27	3.27
Slater	Oilers	12	1.9	1.9	1.9	1.9	3.2	3.2	3.2	2.92
Fairview	Oilwell	12	1.34	0	0	0	3.49	0	0	0
Carolina	Oklahoma	12	0	0	0	0	3.06	3.06	3.06	3.06
Victor	Olancha	12	0.16	0.16	0.16	0.16	2.44	2.44	2.1	1.78
Twentynine Palms	OldDale	4.8	0.9	0	0	0	0.7	0	0	0
Victor	OldTrails	33	2.58	2.58	2.58	2.58	0	0	0	0
Telegraph	Olds	12	2.95	2.95	2.95	2.95	3.4	3.4	3.4	3.4
Flanco	Oleander	4.16	0.61	0.61	0.61	0.61	1.29	0.73	0.57	0.48
Porterville	Olive	4.16	0	0	0	0	0	0	0	0
Alessandro	Oliver	33	0	0	0	0	0	0	0	0
Rosemead	Olney	16	3.58	3.58	3.58	3.58	8.52	7.1	6.41	5.95
Levy	Olson	16	0.3	0.3	0.3	0.3	8.12	6.36	5.73	5.32
O'neill	Olympiad	12	1.92	1.92	1.92	1.92	2.76	2.76	2.07	1.74
Trask	Omaha	12	0	0	0	0	3.34	3.34	3.34	2.97
Telegraph	Omega	12	0.82	0.82	0.82	0.82	3.07	3.07	2.59	2.18
Yucca	Onaga	12	0.15	0.15	0.15	0.15	2.39	2.16	1.71	1.45
Jefferson	Onbord	12	1.4	1.4	1.4	1.4	3.07	2.58	2.08	1.73
Blythe City	Onion	12	1.17	1.17	1.17	1.17	3.18	3.18	3.18	3.18
Edgewater	Onyx	4.16	0	0	0	0	0.59	0	0	0
Redondo	Opal	4.16	1.01	0	0	0	0.72	0	0	0
Rush	Opportunity	16	0.31	0.31	0.31	0.31	7.49	6.18	5.6	5.18
Sunnyside	Ora	4.16	0	0	0	0	1.14	0.68	0.48	0.4
Venida	OrangeBlossom	12	0	0	0	0	0	0	0	0
Gisler	Orbiter	12	2.72	2.72	2.72	2.72	3.27	3.27	3.27	3.27
Carmenita	Orchardale	12	3.54	3.46	3	3	0	0	0	0
Rolling Hills	Orchid	4.16	0.47	0	0	0	0.57	0	0	0
Locust	Oregon	4.16	1.01	0	0	0	1.06	0	0	0
Talbert	Oriole	12	0	0	0	0	3.22	3.22	3.22	3.22
Lockheed	Orion	16	0	0	0	0	5.25	4.73	3.99	3.69
Broadway	Orizaba	12	3.02	3.02	3.02	3.02	3.46	3.46	3.46	3.46
Naples	Orlena	4.16	0	0	0	0	1.02	0.64	0.54	0.41
Olympic	Orsatti	4.16	0	0	0	0	0.95	0	0	0
Villa Park	Orvil	12	0	0	0	0	3.41	3.41	3.41	3.41
Sunnyside	Osgood	4.16	0.15	0.15	0.15	0.15	1.12	0.56	0.44	0.37
Delano	Osner	12	0	0	0	0	0	0	0	0
Ontario	Ostran	4.16	0.54	0.54	0.54	0.54	1.27	0.74	0.57	0.48
Cudahy	Otis	16	0	0	0	0	6.77	5.71	5.12	4.74
Francis	Otter	12	0	0	0	0	3.33	3.33	3.33	3.12
Downey	Otto	4.16	0	0	0	0	0.49	0.49	0.39	0.33
Rio Hondo	Ottowa	12	0	0	0	0	2.9	2.9	2.47	2.1
Palm Village	Ounce	12	0	0	0	0	0	0	0	0
Outlaw P.T.	Outlaw	12	0.6	0.6	0.6	0.6	3.47	3.47	3.47	3.47
Victor	Outpost	12	2.33	2.33	2.33	2.33	3.1	3.1	3.1	2.66
Bolsa	Outrigger	12	3.02	3.02	3.02	3.02	3.25	3.25	3.25	2.96
Visalia	Oval	4.16	0	0	0	0	0	0	0	0
Calcity 'B'	Overall	12	0	0	0	0	0	0	0	0
Windsor Hills	Overhill	4.16	0.2	0.2	0.2	0.2	1.17	0.67	0.53	0.44
Culver	Overland	4.16	0	0	0	0	0.7	0	0	0
Palm Canyon	Overlook	4.16	0	0	0	0	0.5	0	0	0

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Corona	Owens	33	7.94	7.94	7.94	7.94	27	14.96	10.84	8.6
Mayflower	Owl	4.16	0	0	0	0	0.59	0	0	0
Yukon	Oxford	4.16	0.69	0.69	0.69	0.69	1.25	0.69	0.69	0.55
Garfield	Oxley	4.16	0	0	0	0	1.09	0.53	0.42	0.35
Cabrillo	Oxy	12	0.29	0.29	0.29	0.29	3.48	3.48	3.48	3.33
Manhattan	Ozone	4.16	0.5	0.5	0.5	0.5	1.14	0.63	0.63	0.53
Seabright	P&G	12	3.02	0	0	0	3.49	0	0	0
Bowl	Pablo	12	0.7	0.7	0.7	0.7	3.11	3.11	3.11	3.11
Pachappa	Pachappa	4.16	0.59	0	0	0	0.76	0	0	0
Mayberry	Pachea	12	0	0	0	0	3.08	3.08	3.08	3.08
Jefferson	Pacifica	12	0.35	0.35	0.35	0.35	3.35	3.35	3.35	3.11
Vera	Packard	12	1.26	0	0	0	3.4	3.4	3.4	3.35
Rector	Packwood	12	0	0	0	0	0	0	0	0
Howard	Pacoma	4.16	0.3	0.3	0.3	0.3	1.09	0.69	0.52	0.44
Anita	Paddock	16	2.15	2.15	2.15	2.15	7.56	6.24	5.65	5.23
Palmdale	Paddy	12	3.02	3.02	3.02	3.02	1.14	1.14	0.93	0.78
Live Oak	Padova	12	1.23	1.23	1.23	1.23	2.9	2.9	2.9	2.66
Santa Barbara	Padre	16	0.11	0.11	0.11	0.11	8.05	6.5	5.86	5.44
Gaviota	Pago	16	10.55	0	0	0	13.2	0	0	0
Pahrump P.T.	PahrumpP.T.25/25#01	25	1.4	0	0	0	3.49	0	0	0
Apple Valley	Pahute	12	0.03	0.03	0.03	0.03	1.69	1.69	1.36	1.15
Tulare	Paige	12	0	0	0	0	0	0	0	0
Palmdale	Paint	12	0.83	0.83	0.83	0.83	2.23	2.23	2.23	2.23
Painted Cave P.T.	PaintedCave	2.4	0.09	0	0	0	1.26	0	0	0
Santa Fe Springs	Painter	12	0	0	0	0	3.21	3.21	3.21	2.76
O'neill	Pajaro	12	3.02	3.02	3.02	3.02	3.42	3.42	3.42	3.42
Auld	Pala	33	27	27	27	27	27	27	27	27
Chase	Palace	12	0	0	0	0	3.28	3.12	2.4	2.02
Rush	Paljay	16	0.39	0.39	0.39	0.39	7.25	6.19	5.52	5.09
Arch Beach	Pallette	4.16	1.4	0	0	0	0.78	0	0	0
Moneta	Palm	4.16	0.17	0.17	0.17	0.17	1.24	0.69	0.69	0.58
Indian Wells	PalmCity	12	0	0	0	0	0	0	0	0
Live Oak	Palmer	12	1.57	1.57	1.57	1.57	2.73	2.73	2.61	2.14
Chino	Palmetto	12	0	0	0	0	3.26	3.26	3.26	3.26
Garnet	Palmview	33	6.09	6.09	6.09	6.09	25.59	25.59	17.94	17.94
Tamarisk	PaloBrea	12	0	0	0	0	0	0	0	0
Eaton	Paloma	16	3.08	3.08	3.08	3.08	9.48	7.2	6.45	5.93
Lynwood	Palomar	4.16	1.01	0	0	0	0.61	0	0	0
Auld	Palomino	12	0	0	0	0	2.83	2.83	2.7	2.24
Potrero	Pampas	16	1.19	1.19	1.19	1.19	6.84	5.77	5.24	4.79
Cameron	PanAmerican	12	3.02	0	0	0	2.58	0	0	0
Fairfax	PanPacific	16	2.59	2.59	2.59	2.59	9.87	7.72	6.45	5.98
Ely	Panama	12	3.25	3.02	3.02	3.02	3.37	3.37	3.37	3.37
Culver	Pancake	4.16	0.78	0	0	0	0.98	0.79	0.47	0.4
Camarillo	Pancho	16	3.97	3.97	3.97	3.97	6.37	5.32	4.79	4.45
Proctor	Pandora	12	0.26	0.26	0.26	0.26	3.48	3.48	3.48	3.44
Downey	Pangborn	4.16	0.12	0.12	0.12	0.12	1.2	0.81	0.63	0.53
Diamond Bar	Panhandle	12	1.41	1.41	1.41	1.41	3.25	3.25	3.25	2.83
Sharon	Panorama	4.16	0.04	0.04	0.04	0.04	0.64	0.4	0.31	0.27
Rolling Hills	Pansy	4.16	0.39	0.39	0.39	0.39	1.17	0.89	0.58	0.49
Lampson	Panther	12	0.81	0.81	0.81	0.81	3.49	3.49	3.49	3.49
Papaya P.T.	Papaya	4.16	0.2	0	0	0	1.29	0	0	0
Pioneer	Papoose	12	3.44	0	0	0	3.49	0	0	0
Randsburg	Pappas	33	0	0	0	0	0	0	0	0
Valdez	Paradise	16	3.97	3.97	3.97	3.97	6.5	5.48	4.89	4.54
Cudahy	Parafine	16	3.97	3.97	3.97	3.97	8.5	7.16	6.1	5.66
Downey	Paramount	4.16	0.32	0.32	0.32	0.32	1.27	0.91	0.7	0.59
Pechanga	Parcela	12	0	0	0	0	2.76	2.76	2.59	2.11
Ganesha	Parcells	12	1.09	1.09	1.09	1.09	3.45	3.45	3.45	3.45
Glen Avon	Parco	12	3.02	3.02	3.02	3.02	3.31	3.31	3.31	3.31
Padua	Parina	12	0.75	0.75	0.75	0.75	2.36	2.36	2.36	2.35
Del Rosa	Parkdale	12	2.51	2.51	2.51	2.51	3.45	3.45	3.45	3.45
Valdez	Parkmore	16	0	0	0	0	6.27	5.49	4.81	4.4
Corona	Parkridge	12	0.1	0.1	0.1	0.1	3.34	3.34	3.34	3.34
Peyton	Parkway	12	2.25	2.25	2.25	2.25	3.36	3.36	3.36	3.05
Stadium	Parma	12	0	0	0	0	3.24	3.24	3.24	3.24
Colorado	Parman	16	2.16	2.16	2.16	2.16	12.62	6.38	5.76	5.35
Sunny Dunes	Parocela	4.16	0.25	0	0	0	0.54	0	0	0
Talbert	Parrot	12	0.46	0	0	0	3.44	0	0	0
Cajalco	Parsons	12	4.54	4.54	4.54	4.54	2.99	2.99	2.68	2.27
Edinger	Parton	4.16	0.19	0	0	0	0.62	0	0	0
Allen	Pasaglen	4.16	0.59	0.59	0.59	0.59	0.91	0.61	0.49	0.41
Pechanga	Pascal	12	0	0	0	0	1.29	1.29	1.1	0.87
Greenhorn	Pascoe	2.4	0	0	0	0	0	0	0	0
Corona	Paseo	12	0.96	0.96	0.96	0.96	3.2	3.2	3.2	3.2
Washington	Pass	12	2.79	2.79	2.79	2.79	3.44	3.44	3.44	3.44
Repetto	Pat	16	0	0	0	0	7.81	6.59	5.9	5.48
Francis	Pate	12	0.87	0.87	0.87	0.87	3.01	3.01	3.01	3.01
Thornhill	Patencio	12	0	0	0	0	3.35	3.35	3.35	3.35
Culver	Pathe	16	3.97	3.97	3.94	3.94	7.89	6.66	5.95	5.5

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Tortilla	Patio	12	0	0	0	0	0	0	0	0
Ojai	Patricia	16	1.83	1.83	1.83	1.83	5.3	4.44	4.06	3.73
Newbury	Patriot	16	0.12	0.12	0.12	0.12	6.7	5.62	5.09	4.71
Milliken	Patron	12	1.27	1.27	1.27	1.27	2.51	2.51	2.51	2.15
Bullis	Pattie	4.16	0.55	0	0	0	0.7	0	0	0
Sawtelle	Patton	16	3.97	0	0	0	6.41	0	0	0
Brookhurst	Paul	12	3.02	3.02	3.02	3.02	3.39	3.39	3.39	3.39
Three Rivers	Pawley	12	0	0	0	0	0	0	0	0
Gavilan (115)	Pawnee	12	0	0	0	0	2.71	2.45	1.95	1.64
Amargo	Paxton	4.16	0	0	0	0	0	0	0	0
Bradbury	Payne	16	1.91	1.91	1.91	1.91	7.57	5.95	5.42	4.99
Hathaway	Peabody	4.16	0	0	0	0	0.54	0	0	0
Parkwood	Peabush	12	6.61	0	0	0	2.6	0	0	0
Fernwood	Peach	16	4.34	4.34	3.97	3.97	9.41	7.59	6.86	6.37
Peacock U.G.S.	Peacock	4.16	1.01	0	0	0	0.92	0	0	0
Peacor P.T.	Peacor	12	1.01	1.01	1.01	1.01	3.34	2.31	2.11	1.54
Chestnut	Peanut	12	0	0	0	0	3.47	3.47	3.47	3.47
Citrus	Pear	12	0.09	0.09	0.09	0.09	3.24	3.24	3.24	2.75
Pierpont	Pearce	4.16	0.67	0.67	0.67	0.67	1.09	0.72	0.62	0.48
Cabrillo	Pearcy	12	1.11	1.11	1.11	1.11	3.35	3.35	3.35	2.98
Palmdale	Pearland	12	0	0	0	0	3.13	3.13	3.13	3.09
Padua	Pebble	12	1.35	1.35	1.35	1.35	3.42	3.42	3.42	3.24
Chestnut	Pecan	12	0.49	0	0	0	3.49	0	0	0
Rush	Peck	16	0.59	0.59	0.59	0.59	7.06	5.89	5.31	4.93
Rio Hondo	Pecos	12	0.38	0.38	0.38	0.38	3.22	3.22	3	2.54
Whipple	Peddler	33	8.38	8.38	8.38	8.38	27	27	22.87	18.09
Pedestrian P.T.	Pedestrian	4.16	0	0	0	0	0.7	0	0	0
San Miguel	Pedro	16	2.61	2.61	2.61	2.61	6.87	5.73	5.16	4.78
Beverly	Peerless	4.16	0	0	0	0	1.27	0.86	0.68	0.56
Moulton	Pekingese	12	5.29	5.29	5.29	3.02	3.45	3.45	3.45	3.45
Talbert	Pelican	12	0.02	0.02	0.02	0.02	3.35	3.35	3.35	3.35
Center	Pellet	12	1.45	1.45	1.45	1.45	2.42	2.42	2.42	2.42
Anaverde	Pelona	12	5.84	5.84	5.84	5.84	3.31	3.31	3.31	3.04
Washington	Penalty	12	0.86	0.86	0.86	0.86	3.38	3.38	3.38	3.19
Santiago	Pence	12	0.67	0.67	0.67	0.67	3.15	3.15	3.07	2.48
Highland	Pencil	12	0	0	0	0	3.36	2.63	2.63	2.21
Yucaipa	Pendleton	12	3.49	3.49	3.49	3.02	3.32	3.32	3.32	3.32
El Nido	Penguin	16	4.31	4.31	4.31	3.97	9.38	7.65	6.5	6.02
Crown	Peninsula	12	0	0	0	0	3.38	3.38	2.69	2.27
La Habra	Penmar	12	1.63	1.63	1.63	1.63	2.98	2.98	2.98	2.98
Fremont	Penrose	16	0	0	0	0	7.3	6.16	5.54	5.14
Aqueduct	Penstock	12	0.93	0.93	0.93	0.93	2.63	1.85	1.41	1.19
Brighton	Penthouse	16	1.92	1.92	1.92	1.92	8.92	7.41	6.68	6.19
Hanford	Peoples	12	0	0	0	0	0	0	0	0
Atwood	Peralta	12	0	0	0	0	3.41	3.41	3.32	2.54
Bayside	Perch	12	0.15	0.15	0.15	0.15	3.24	3.24	3.24	2.85
Timberwine	Perimeter	12	0	0	0	0	0	0	0	0
Gallatin	Perkins	12	0	0	0	0	3.46	3.46	3.46	3.46
Perris P.T.	Perris	12	0.67	0.67	0.67	0.67	3.49	3.49	3.49	3.49
Arro	Pershing	4.16	0	0	0	0	0.77	0	0	0
Modena	Persia	12	0.55	0.55	0.55	0.55	3.14	3.14	3.14	2.83
Tortilla	Peso	12	0	0	0	0	0	0	0	0
Piute	Petan	12	1.67	1.67	1.67	1.67	0.41	0.29	0.21	0.18
Telegraph	Pete	12	0.37	0.37	0.37	0.37	3.34	3.34	3.34	3.09
Roadway	Peterbilt	12	1.82	1.82	1.82	1.82	0	0	0	0
Wakefield	Petit	16	7.51	3.97	3.97	3.97	8.35	6.97	6.28	5.83
Bassett	Petri	12	0	0	0	0	3.38	3.38	3.38	3.04
La Fresa	Petrol	16	6.05	6.05	3.97	3.97	7.7	6.43	5.81	5.39
Timoteo	Pettis	12	2.92	2.92	2.92	2.92	3.42	3.42	3.42	3.42
Pheasant P.T.	Pheasant	12	0.28	0.28	0.28	0.28	3.45	3.45	3.45	3.45
Lancaster	Phillips	12	3.11	3.02	3.02	3.02	3.26	3.26	3.26	3.26
Parkwood	Phoenix	12	3.13	3.13	3	3	3.38	3.38	3.38	3.38
Santa Rosa	Physician	12	0	0	0	0	0	0	0	0
Niguel	Piano	12	1.89	1.89	1.89	1.89	2.01	2.01	1.83	1.54
Mesa	Picador	16	0	0	0	0	9.4	6.32	5.7	5.3
Niguel	Piccolo	12	0.1	0.1	0.1	0.1	3.49	3.49	3.49	3.49
Acton	Pick	12	3.02	3.02	3.02	3.02	2.87	2.87	2.71	2.14
La Canada	Pickens	16	0	0	0	0	10.09	6.74	5.93	5.51
Santa Monica	Pickering	4.16	0.89	0.89	0.89	0.89	1.27	0.88	0.74	0.57
Bridgeport	PickleMeadows	16	0	0	0	0	0	0	0	0
Pauba	Piconi	12	0.61	0.61	0.61	0.61	2.53	2.53	2.29	1.94
Fair Oaks	Piedmont	4.16	0	0	0	0	0.72	0	0	0
Newcomb	Piedra	12	4.76	3.02	3.02	3.02	3.35	3.35	2.62	2.21
Garnet	Pierson	33	0	0	0	0	0	0	0	0
Stadler	Pigskin	12	0	0	0	0	2.4	2.4	2.4	2.21
Bayside	Pike	12	0	0	0	0	3.29	3.29	3.29	3.09
Arcadia	Pilgrim	16	3.65	3.65	0	0	7.93	6.78	6.11	5.47
Pico	Pilot	12	3.02	0	0	0	3.49	0	0	0
Lunada	Pima	4.16	1.01	1.01	1.01	1.01	0.58	0.58	0.43	0.35
Idyllwild	PineCove	12	1.42	1.42	1.42	1.42	3.31	3.31	3.12	2.65

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Citrus	Pineapple	12	0.54	0.54	0.54	0.54	3.14	3.14	3.14	2.72
Brewster	Pinehurst	4.16	0	0	0	0	1.08	0.63	0.51	0.42
Cajalco	Pinewood	12	0	0	0	0	0.63	0.63	0.55	0.46
Orange	Pink	12	0	0	0	0	0	0	0	0
Johanna	Pinochle	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Chestnut	Pinon	12	5.55	3.02	3.02	3.02	3.06	3.06	3.06	3.06
Lighthipe	Pint	12	4.21	3.02	3.02	3.02	3.47	3.47	3.47	3.47
Hi Desert	Pinto	33	8.38	8.38	8.38	8.38	18.9	10.77	8.22	5.92
Northwind	Pinwheel	12	3.02	3.02	3.02	3.02	0	0	0	0
Rolling Hills	Pinzon	16	3.97	3.97	3.97	3.97	9.21	7.43	6.71	6.19
Yucca	Pioneertown	12	3.02	3.02	3.02	3.02	2.36	2.33	1.85	1.56
Olinda	Pipeline	12	2.49	0	0	0	3.3	3.3	3.3	3.3
Santa Rosa	Piper	12	0	0	0	0	0	0	0	0
Cudahy	Pirate	16	0	0	0	0	6.78	5.71	5.13	4.76
Estrella	Pisces	12	0	0	0	0	3.49	3.49	3.49	3.49
Chestnut	Pistachio	12	1.3	1.3	1.3	1.3	3.43	3.43	3.43	3.43
Concho	Pistola	12	0	0	0	0	0	0	0	0
Ditmar	Piston	16	0	0	0	0	8.25	6.68	6.02	5.59
Rio Hondo	Pit	16	3.97	0	0	0	8.41	0	0	0
San Antonio	Pitzer	12	0	0	0	0	3.24	3.24	3.24	3.21
Pioneer	Piuma	4.16	0	0	0	0	1.16	0.48	0.48	0.41
Trophy	Place	12	0.03	0.03	0.03	0.03	3.4	3.4	3.4	3.4
Saugus	Placerita	16	0	0	0	0	7.11	5.94	5.46	4.94
Timoteo	Placid	12	0.49	0.49	0.49	0.49	1.64	1.27	1	0.85
Porterville	Plano	12	0	0	0	0	0	0	0	0
Sun City	Plasma	12	0.88	0.88	0.88	0.88	3.34	3.34	3.34	2.85
Crater	Plateau	16	0	0	0	0	4.58	3.85	3.46	3.22
Limestone	Platinum	12	0	0	0	0	3.4	3.4	3.4	3.06
Firehouse	Platoon	12	0	0	0	0	3.43	3.43	3.43	3.36
Brewster	Platt	4.16	0.24	0	0	0	0.7	0	0	0
Beverly	Playboy	16	1.67	1.67	1.67	1.67	7.49	6.29	5.64	5.25
Eisenhower	Player	33	2.85	2.85	2.85	2.85	27	27	21.67	16.37
Moraga	Playhouse	12	0	0	0	0	2.77	2.77	2.31	1.91
Athens	Plum	4.16	0.07	0.07	0.07	0.07	1.21	0.8	0.63	0.53
Tamarisk	Plumley	12	0	0	0	0	0	0	0	0
Cajalco	Plummer	12	1.32	1.32	1.32	1.32	0	0	0	0
Atwood	Plumosa	12	0.75	0.75	0.75	0.75	3.11	3.11	3.11	3.11
Bluff Cove	Pluto	4.16	0	0	0	0	0.82	0.82	0.59	0.5
Inglewood	Plymouth	4.16	0.75	0.75	0.75	0.75	1.27	0.89	0.71	0.58
La Palma	Pocket	12	7.68	0	0	0	3.45	0	0	0
Tortilla	Poco	33	0	0	0	0	0	0	0	0
Edgewater	Point	4.16	0	0	0	0	0.64	0	0	0
Trona	PointOfRocks	12	0	0	0	0	0	0	0	0
Johanna	Poker	12	0.42	0.42	0.42	0.42	3.48	3.48	3.48	3.48
Barstow	Police	12	0	0	0	0	0	0	0	0
Wave	Polk	12	0.06	0.06	0.06	0.06	3.01	3.01	3.01	2.79
Fairview	Pollard	12	2.78	0	0	0	3.47	3.47	3.47	3.47
Santa Rosa	Polo	12	0	0	0	0	0	0	0	0
Temescal P.T.	Polymer	12	2.31	2.31	0	0	0.39	0.39	0.39	0.39
Francis	Pomall	12	0	0	0	0	3.25	3.25	3.25	2.94
Terrace	Pomeroy	4.16	0.26	0	0	0	0.68	0	0	0
Browning	Pond	12	0	0	0	0	0	0	0	0
Colonia	Ponderosa	16	2.72	2.72	2.72	2.72	5.66	4.76	4.28	3.98
Vera	Pontiac	12	1.66	1.66	1.66	1.66	3.32	3.32	3.32	3.32
Auld	Pony	33	8.38	8.38	8.38	8.38	27	27	27	19.35
Moulton	Poodle	12	2.93	2.93	2.93	2.93	3.48	3.48	3.48	3.48
West Barstow	Pool	4.16	0	0	0	0	0	0	0	0
Cabazon	PoppetFlats	12	3.02	3.02	3.02	3.02	3.43	3.43	2.85	2.42
Sunnyside	Poppy	12	0	0	0	0	3.35	3.35	3.35	3.32
Temescal P.T.	Porcelain	4.16	1.01	1	1	1	0.92	0.6	0.5	0.39
Corona	Porphyry	33	17.25	8.38	8.38	8.38	27	27	22.15	16.4
Delano	Port	12	0	0	0	0	0	0	0	0
Victor	Portland	33	0	0	0	0	0	0	0	0
Palm Village	Portola	4.8	0	0	0	0	0	0	0	0
Proctor	Poseidon	12	3.02	0	0	0	3.49	0	0	0
Trona	Potash	12	0	0	0	0	0	0	0	0
Sixteenth Street	Potato	12	2.83	2.83	2.83	2.83	3.35	3.35	3.35	3
Lathrop Wells P.T.	Potosi	25	0.58	0	0	0	3.49	0	0	0
Elsinore	Pottery	12	3.02	3.02	3.02	3.02	2.84	2.84	2.84	2.84
Yucaipa	Poultry	12	1.54	1.54	1.54	1.54	2.25	2.02	1.59	1.35
Palm Village	Pound	12	0	0	0	0	0	0	0	0
Auld	Pourroy	12	1.59	1.59	1.59	1.59	3.31	3.31	3.31	2.81
Rio Hondo	Powder	16	0	0	0	0	6.09	4.92	4.44	4.12
Newhall	Powell	16	0	0	0	0	7.35	6.07	5.47	5.09
Muscoy	Power	4.16	0	0	0	0	1.24	0.85	0.67	0.56
Potrero	Prado	16	0	0	0	0	9.34	7.61	6.85	6.34
Strathmore	Prairie	12	0	0	0	0	0	0	0	0
Woodville	Pratt	12	0	0	0	0	0	0	0	0
Savage	Prayer	12	0.67	0.67	0.67	0.67	1.24	1.06	0.82	0.7
Stetson	Predator	12	0.65	0.65	0.65	0.65	3.04	3.04	3.01	2.51

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Padua	Prego	12	1.76	1.76	1.76	1.76	2.82	2.82	2.82	2.42
Cornuta	President	12	0	0	0	0	3.36	3.36	3.36	2.85
Newcomb	Presley	12	1.52	1.52	1.52	1.52	3.35	3.35	3.09	2.61
Colton	Preston	12	1.59	1.59	1.59	1.59	1.49	1.29	0.99	0.84
Corona	Price	12	2.63	2.63	2.63	2.63	3.03	3.03	2.66	2.25
Cypress	Prida	12	2.83	2.83	2.83	2.83	3.48	3.48	3.48	3.48
Viejo	Primero	12	0	0	0	0	3.26	3.26	3.26	3.26
Bradbury	Primrose	16	0.06	0.06	0.06	0.06	7.6	6.38	5.75	5.34
Calden	Prince	16	8.17	5.95	5.95	3.97	9.47	7.88	7.1	6.55
Gage	Priory	4.16	1.01	0	0	0	0.61	0	0	0
Basta	Pritchard	4.16	0.34	0.34	0	0	1.28	0.69	0.55	0.46
Parkwood	Privet	12	1.21	1.21	1.21	1.21	2.91	2.91	2.91	2.91
Santa Rosa	Probst	33	0	0	0	0	0	0	0	0
Narod	Products	12	5.57	5.57	3	3	3.48	3.48	3.48	3.12
Isla Vista	Professor	16	0.02	0.02	0.02	0.02	8.86	7.3	6.45	5.99
Pedley	Profit	12	0	0	0	0	3.17	3.17	3.05	2.58
Corona	Promenade	12	0.56	0.56	0.56	0.56	3.48	3.48	3.48	3.48
Del Sur	Pronghorn	12	2.21	2.21	2.21	2.21	0	0	0	0
Naples	Prospect	4.16	0.06	0.06	0.06	0.06	1.17	0.79	0.64	0.5
Pruitt P.T.	Pruitt	4.16	0.6	0	0	0	1.29	0	0	0
Parkwood	Prune	12	0	0	0	0	3.33	3.33	3.33	3.33
Etiwanda	Pryor	12	1.28	1.28	1.28	1.28	3.12	3.12	3.12	2.96
Layfair	Puddingstone	12	1	1	1	1	3.47	3.47	3.47	3.17
La Fresa	Pueblo	16	5.52	5.52	3.97	3.97	9.35	7.58	6.83	6.34
Modoc	Puesta	4.16	0.19	0.19	0.19	0.19	0.65	0.3	0.24	0.2
Corona	Pulaski	12	0.3	0.3	0.3	0.3	3.47	3.47	3.47	3.47
Ditmar	Pullman	4.16	0	0	0	0	1.16	0.77	0.6	0.51
Fruitland	Pulp	16	1.01	1.01	1.01	1.01	8.45	6.97	6.28	5.82
Del Rosa	Pumalo	12	3.79	3.02	3.02	3.02	3.43	3.43	3.43	3.38
Chiquita	Punch	12	0.68	0.68	0.68	0.68	3.39	3.39	3.39	3.27
Washington	Punt	12	3.02	3.02	3.02	3.02	3.45	3.45	3.45	3.45
Outlet P.T.	Purchase	12	3.02	3.02	3.02	3.02	1.49	1.49	1.49	1.49
Sawtelle	Purdue	16	4.96	4.96	4.96	4.96	8.92	6.61	6.61	6.14
Cudahy	Purex	16	3.97	3.97	3.97	3.97	8.58	7.18	6.45	5.98
Orange	Purple	12	0	0	0	0	3.47	0	0	0
San Gabriel	Putney	4.16	0	0	0	0	1.24	0.78	0.61	0.51
Gilbert	Putter	12	3.02	3.02	3.02	3.02	3.44	3.44	3.44	3.09
Wakefield	Pyle	16	6.14	3.97	3.97	3.97	7.7	6.41	5.77	5.35
Savage	Pyramid	12	1.82	1.82	1.82	1.82	3.24	3.17	2.52	2.14
Parkwood	Pyrus	12	3.28	3.02	3.02	3.02	3.24	3.24	3.24	2.82
North Oaks	Python	16	0	0	0	0	5.18	4.11	3.71	3.44
Modena	Qatar	12	0	0	0	0	2.95	2.95	2.51	2.12
Tipton	Quail	12	0	0	0	0	0	0	0	0
Layfair	Quaker	4.16	0.28	0.28	0.28	0.28	0.71	0.71	0.43	0.37
Pedley	Quarry	12	0.38	0.38	0.38	0.38	2.25	2.25	2.08	1.73
Palm Village	Quart	12	0	0	0	0	0	0	0	0
Placentia	Quarter	12	2	0	0	0	3.49	0	0	0
Stadler	Quarterback	12	2.65	2.65	2.65	2.65	3.01	3.01	3.01	3.01
Limestone	Quartz	12	0.1	0.1	0.1	0.1	3.48	3.48	3.32	2.76
Sun City	Quasar	12	1.23	1.23	1.23	1.23	3.35	3.35	3.35	3.35
Imperial	Quebec	4.16	0.35	0.35	0.35	0.35	1.29	0.85	0.67	0.56
Inglewood	Queen	4.16	1.01	0	0	0	0.76	0	0	0
Queen Mary U.G.S.	QueenMary1	4.16	0.88	0	0	0	1.21	0	0	0
Lancaster	Queensland	12	0	0	0	0	3.05	3.05	3.03	2.56
Crest	Quicksilver	16	4.53	3.97	3.97	3.97	8.69	7.32	6.55	6.07
Anaverde	Quinby	12	0.85	0.85	0.85	0.85	2.74	2.74	2.74	2.44
Broadway	Quincy	4.16	0.65	0	0	0	0.76	0	0	0
Soquel	Quinto	12	2.1	2.1	2.1	2.1	3.2	3.2	3.2	2.98
Southwind	Quixote	12	3.02	0	0	0	0	0	0	0
Lucerne	Rabbit	12	2.34	2.34	2.07	2.07	2.35	1.58	1.35	1.06
North Oaks	Racer	16	3.97	0	0	0	6.86	0	0	0
Trophy	Raceway	12	0	0	0	0	3.14	3.14	3.14	2.76
Villa Park	Racine	12	0	0	0	0	3.12	3.12	3.12	3.07
Holiday	RacquetClub	4.16	1.18	0	0	0	0.91	0	0	0
Villa Park	Radec	12	0.33	0.33	0.33	0.33	3.4	3.4	3.4	3.4
Cypress	Radford	12	1.68	1.68	1.68	1.68	3.46	3.46	3.46	3.2
La Fresa	Radiator	16	13.2	13.2	13.2	3.97	7.22	7.22	7.22	6.52
Cherry	Radium	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Delano	Radnor	12	0	0	0	0	0	0	0	0
Cucamonga	Rahal	12	0	0	0	0	3.46	3.46	3.46	3.22
Carson	Rahn	16	3.55	3.55	3.55	3.55	7.06	5.9	5.34	4.95
Slater	Raiders	12	2.35	2.35	2.35	2.35	3.35	3.35	3.35	3.14
Somis	Rainbow	16	4.74	3.97	3.94	3.94	6.47	5.38	4.78	4.44
Sixteenth Street	Raisin	12	0.9	0.9	0.9	0.9	3.42	3.42	3.42	3.42
San Marino	Raleigh	4.16	0.06	0.06	0.06	0.06	1.2	0.77	0.48	0.41
Wabash	Ralston	16	8.69	3.97	3.97	3.97	8.79	7.52	6.63	6.09
Estero	Ramac	16	5.52	3.97	3.97	3.94	5.95	5	4.45	4.14
Vera	Rambler	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Bunker	Rambo	12	2.02	2.02	2.02	2.02	3.35	3.35	3.35	3.25
Stadium	Ramp	12	0	0	0	0	3.12	3.12	2.97	2.52

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Slater	Rams	12	2.81	2.81	2.81	2.81	3.23	3.23	3.23	3.07
Ganesha	Ramsey	4.16	0.29	0	0	0	0.61	0	0	0
Chase	Ramsgate	12	0	0	0	0	2.46	2.46	2.46	2.29
Farrell	Rana	12	1.71	1.71	1.71	1.71	2.5	2.5	2.5	2.29
O'neill	Ranch	12	1.56	1.56	1.56	1.56	3.28	3.28	3.28	3.28
Santiago	Rand	12	0	0	0	0	3.49	3.49	3.49	3.49
Ranger P.T.	Ranger	2.4	0.3	0	0	0	1.13	0	0	0
Maraschino	Ranier	12	3.02	3.02	3	3	0	0	0	0
Walker Basin	Rankin	12	0.72	0.72	0.72	0	3.48	3.48	3.25	2.65
Belmont	Ransom	4.16	0.75	0.75	0.75	0.75	1.21	0.79	0.6	0.5
Sunny Dunes	Rapfeal	4.16	0	0	0	0	0.82	0	0	0
Oak Grove	Rasmussen	12	0	0	0	0	0	0	0	0
Sunnyside	Raton	4.16	0	0	0	0	0.86	0.59	0.45	0.38
North Oaks	Rattler	16	1.2	0	0	0	7.36	0	0	0
Talbert	Raven	12	2.41	0	0	0	3.12	0	0	0
Cypress	Ravenna	12	0	0	0	0	3.49	3.49	3.49	3.49
Arroyo	Ravine	16	0.62	0.62	0.62	0.62	8.76	6.3	5.68	5.28
Auld	Rawson	12	4.38	4.38	3.02	3.02	3.23	3.23	3.23	3.23
Fullerton	Raybestos	12	0.78	0.78	0.78	0.78	3.49	3.49	3.49	3.49
Bullis	Rayborn	4.16	0.01	0.01	0.01	0.01	1.27	0.67	0.67	0.55
Anaverde	Rayburn	12	3.85	3.02	3.02	3.02	3.1	3.1	3.1	3.1
Palmdale	Razor	12	2.76	2.76	2.76	2.76	3.37	3.37	3.37	3.37
San Miguel	Ready	16	2.12	2.12	2.12	2.12	7.17	6.1	5.45	5.04
Alessandro	Reagan	12	0.4	0.4	0.4	0.4	3.47	3.47	3.47	2.8
Maxwell	Reakes	12	3.28	0	0	0	3.31	0	0	0
Fremont	Reasoner	16	2.26	2.26	2.26	2.26	7.36	6.18	5.57	5.16
Bedford	Rebel	4.16	0.13	0	0	0	0.74	0	0	0
Maxwell	Reche	12	0	0	0	0	3.45	3.45	3.45	3.45
Orange	Red	12	0.81	0.81	0.81	0.81	3.49	3.49	3.49	3.49
North Muroc	RedBarn	12	0	0	0	0	0	0	0	0
Red Box	RedBox	16	1.93	1.93	1.93	1.93	8.84	5.01	4.47	4.1
Center	RedFlag	12	6.13	6.13	6.13	3.02	3.34	3.34	3.34	3.34
Casitas	RedMountain	16	3.97	3.97	3.97	3.97	6.14	5.36	4.67	4.32
Bloomington	Redball	12	0	0	0	0	3.36	3.36	3.05	2.58
Venice Hill	Redbanks	12	0	0	0	0	0	0	0	0
Torrance	Redgum	16	3.97	0	0	0	7.74	0	0	0
Fairview	Redhill	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Stoddard	Redick	4.16	1.01	0	0	0	0.79	0	0	0
Hanford	Redington	12	0	0	0	0	0	0	0	0
Milliken	Redlabel	12	0	0	0	0	3.49	3.49	3.49	3.45
Pioneer	Redskin	12	7.94	7.94	7.94	6.05	3.49	3.49	3.49	3.49
Estero	Redstone	16	0	0	0	0	6.25	5.28	4.73	4.4
Declez	Redwood	12	1.72	1.72	1.72	1.72	3.19	3.19	3.19	3.14
Mentone	Reed	12	0.33	0.33	0.33	0.33	2.95	2.95	2.95	2.95
Cortez	Reeder	12	0.98	0.98	0.98	0.98	3.2	3.2	3.2	3.2
Larder	Reeves	4.16	0.28	0	0	0	0.9	0	0	0
Stadler	Referee	12	0	0	0	0	2.81	2.81	2.81	2.75
Carmenita	Refoil	12	2.07	2.07	2.07	2.07	3.36	3.36	3.36	3.16
Cameron	Regal	12	0.9	0.9	0.9	0.9	3.23	3.23	3.23	3.23
San Vicente	Regent	4.16	1.52	0	0	0	0.61	0	0	0
Rivera	Regina	4.16	0	0	0	0	0.7	0	0	0
Colonia	Reimann	16	3.97	3.94	3.94	3.94	5.09	4.29	3.84	3.57
Silver Spur	Rein	12	0	0	0	0	0	0	0	0
Pepper	Reisling	12	4.52	4.52	4.52	3.02	3.4	3.4	3.4	3.4
Royal	Rejada	16	2.2	2.2	2.2	2.2	7.11	5.89	5.25	4.87
Vail	Relief	16	0.1	0	0	0	7.6	0	0	0
Merced	Relish	12	0	0	0	0	3.42	3.42	3.42	3.13
Barstow	Remote	33	0	0	0	0	0	0	0	0
Lennox	Republic	16	4.96	4.96	3.94	3.94	7.86	6.58	5.94	5.52
Nelson	Resort	33	8.38	8.38	8.38	8.38	7	3.44	2.28	1.73
Retreat P.T.	Retreat	12	6.33	3.78	3.78	3.78	3.49	3.49	3.49	3.49
June Lake	ReversePeak	12	0	0	0	0	0	0	0	0
Imperial	Rex	4.16	0.01	0.01	0.01	0.01	1.21	0.6	0.6	0.5
Beverly	Rexford	4.16	0.87	0	0	0	0.91	0	0	0
Cudahy	Rheem	16	4.96	0	0	0	7.25	0	0	0
Rio Hondo	Rhine	12	0.5	0.5	0.5	0.5	3.17	3.17	3.17	3.17
San Dimas	Rhoads	12	4.18	4.18	3	3	3.15	3.15	3.15	3.15
Crater	Rhoda	16	3.28	3.28	3.28	3.28	0	0	0	0
Carolina	Rhodelsland	12	3.02	3.02	3.02	3.02	3.47	3.47	3.47	3.47
Brighton	Rhumba	16	2.05	2.05	2.05	2.05	9.07	7.24	6.51	6.05
San Miguel	Ricardo	16	6.52	3.97	3.97	3.94	6.96	5.71	5.17	4.79
Oxnard	Rice	4.16	0.43	0.43	0.43	0.43	1.27	0.64	0.64	0.54
Costa Mesa	Richards	4.16	1.52	1.4	1.4	1.01	1.27	0.91	0.58	0.49
Vestal	Richgrove	12	0	0	0	0	0	0	0	0
Fullerton	Richman	4.16	0.05	0.05	0.05	0.05	1.25	0.87	0.67	0.56
Richuson P.T.	Richuson	4.16	1.01	0	0	0	1.28	0	0	0
Parkwood	RickO	12	0.93	0.93	0.93	0.93	3.35	3.35	3.35	2.86
Edwards	Rickenback	33	0	0	0	0	0	0	0	0
Inyokern	Rickover	33	0	0	0	0	0	0	0	0
Gorman	Ridge	12	6.83	6.83	6.05	3.02	3.48	3.09	2.36	2

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Walteria	Ridgeland	4.16	0	0	0	0	1.01	0.6	0.47	0.39
Newcomb	Ridgemoor	12	0.41	0.41	0.41	0.41	3.28	2.93	2.93	2.43
Vestal	Rieck	12	0	0	0	0	0	0	0	0
Center	Rifle	12	4.22	4.22	3.46	3	3.43	3.43	3.43	3.43
Newmark	Riggin	4.16	0	0	0	0	0.82	0.82	0.65	0.54
Wimbledon	Riggs	12	2.92	2.92	2.92	2.92	3.49	3.49	3.49	3.49
Cardiff	Riley	12	4.02	3.78	3.78	3.02	3.11	3.11	3.11	3.02
Burnt Mill	Rim	12	1.26	1.26	1.26	1.26	3.42	3.42	3.19	2.66
Culver	Rimpau	4.16	0.22	0	0	0	0.58	0	0	0
Morro	Rimrock	12	1.48	1.48	1.48	1.48	3.44	3.44	3.44	3.44
Rincon P.T.	Rincon	4.16	0.07	0	0	0	1.19	0	0	0
Saugus	Riner	16	3.77	3.77	3.77	3.77	5.14	4.09	3.7	3.39
Cabrillo	Ringo	12	1.33	1.33	1.33	1.33	2.83	2.83	2.83	2.83
Tulare	Rinker	12	0	0	0	0	0	0	0	0
Thunderbird	RioDelSol	4.8	0	0	0	0	0	0	0	0
Riverway	RioGrande	12	0	0	0	0	0	0	0	0
Santa Monica	Riptide	16	1.58	1.58	1.58	1.58	7.75	6.31	5.71	5.3
Huntington Park	Rita	4.16	0.35	0	0	0	0.88	0	0	0
Grangeville	Ritchie	4.16	0	0	0	0	0	0	0	0
Anaverde	Ritter	12	0.12	0.12	0.12	0.12	3.44	3.44	3.44	3.44
Casitas	Riva	16	0.23	0.23	0.23	0.23	6.09	4.96	4.47	4.16
Alessandro	Rivard	12	0.83	0	0	0	3.4	3.4	3.4	3.31
Olive Lake	RiverBend	12	6.57	6.05	3.02	3.02	3.04	3.04	2.73	2.3
Bassett	Rivergrade	12	3.02	3.02	3.02	3.02	3.46	3.46	3.46	3.46
Bandini	Riverside	16	1.91	1.91	1.91	1.91	9.11	7.55	6.86	6.34
Second Avenue	Riverview	12	4.54	4.54	4.54	4.54	3.47	3.47	3.47	3.47
Downey	Rives	4.16	0.27	0.27	0.27	0.27	1.2	0.66	0.51	0.43
Bridge	Rivet	4.16	0.75	0.75	0.75	0.75	1.22	0.83	0.65	0.55
Santa Barbara	Riviera	4.16	1.01	1.01	1.01	1.01	0.86	0.39	0.31	0.26
Cajalco	Roadrunner	12	0.88	0.88	0.88	0.88	2.73	2.69	2.16	1.8
Granada	Roanoke	4.16	0.01	0	0	0	0.92	0	0	0
Arcadia	Robbie	16	1.98	1.98	1.98	1.98	8.46	7.11	6.41	5.95
Olympic	Robertson	4.16	1	0	0	0	0.61	0	0	0
Wrightwood	Robin	12	0.47	0.47	0.47	0.47	3.44	2.98	2.34	1.94
Randolph	Robinson	16	2.67	2.67	2.67	2.67	8.73	7.65	6.69	6.12
Bridgeport	RobinsonCreek	12	0	0	0	0	0	0	0	0
State Street	Roble	12	3.02	3.02	3.02	3.02	3.46	3.46	3.46	3.46
Neptune	Rocha	4.16	0.18	0.18	0.18	0.18	1.09	0.5	0.5	0.42
Kempster	Rochholtz	4.16	0	0	0	0	0.63	0	0	0
San Antonio	Rock	12	0.83	0.83	0.83	0.83	3.31	3.31	3.31	3.18
Sherwin	Rockcreek	12	0	0	0	0	0	0	0	0
Hedda	Rocket	4.16	0.08	0	0	0	0.63	0	0	0
Downs	RocketTown	12	0	0	0	0	0	0	0	0
Walnut	Rockhill	12	1.25	1.25	1.25	1.25	3.04	3.04	3.04	2.78
Elsinore	Rockridge	12	3.64	3.02	3.02	3.02	2.17	2.17	1.76	1.49
Tennessee	Rockwell	12	2.07	2.07	2.07	2.07	3.07	3.07	3	2.54
Beverly	Rodeo	4.16	0	0	0	0	0.64	0	0	0
Stewart	Rodney	12	1.12	0	0	0	3.49	0	0	0
Pierpont	Roebuck	4.16	0.61	0.61	0.61	0.61	1.22	0.71	0.55	0.46
Venida	Roeding	12	0	0	0	0	0	0	0	0
Terrace	Rogers	4.16	0.87	0	0	0	0.99	0	0	0
Shandin	Roi-Tan	12	0.25	0.25	0.25	0.25	3.16	3.16	3.13	2.62
Fullerton	Roma	12	0.04	0.04	0.04	0.04	3.44	3.44	3.44	3.44
Haskell	Romanus	16	1.85	1.85	1.85	1.85	5.83	4.82	4.35	4.04
Pechanga	Romero	12	1.47	1.47	1.47	1.47	2.93	2.93	2.65	2.24
MacArthur	Rommel	12	0	0	0	0	2.76	2.72	2.16	1.83
Ronnie P.T.	Ronnie	4.16	1.01	0	0	0	1.29	0	0	0
La Habra	Ronwood	12	1.22	1.22	1.22	1.22	3.32	3.32	3.32	3.32
Redman	Roosevelt	12	8.91	8.91	3.02	3.02	0	0	0	0
Moraga	Roripaugh	12	1.39	1.39	1.39	1.39	1.8	1.8	1.8	1.8
Camarillo	Rosa	16	0	0	0	0	5.87	4.87	4.37	4.06
Sunnyside	Rose	12	3.02	3.02	3.02	3.02	3.47	3.47	3.47	3.43
Pitman	Rosebud	12	0	0	0	0	0	0	0	0
Lindsay	Rosedale	12	0	0	0	0	0	0	0	0
Amador	Roseglen	16	4.67	3.94	3.94	3.94	12.81	5.95	5.95	5.53
Ganesha	Roselawn	12	1.93	1.93	1.93	1.93	0	0	0	0
Perry	Rosemary	4.16	0.42	0.42	0.42	0.42	1.23	0.87	0.68	0.57
La Canada	Rosemont	16	1.39	1.39	1.39	1.39	6.42	5.23	4.2	4.2
Eric	Roseton	12	2.31	2.31	2.31	2.31	3.41	3.41	3.41	3.41
Rialto	Rosewood	4.16	0.89	0	0	0	1.05	0	0	0
Padua	Rossi	12	1	1	1	1	3.26	3.26	3.26	3.26
Cypress	Rossmoor	12	0	0	0	0	3.07	3.07	3.07	2.91
Chino	Roswell	12	1.7	1.7	1.7	1.7	2.86	2.86	2.86	2.82
Stetson	Rotec	12	0	0	0	0	2.89	2.89	2.54	2.15
Gilbert	Rough	12	2.85	0	0	0	3.49	0	0	0
Corona	Roulette	12	1.92	1.92	1.92	1.92	3.46	3.46	3.46	3.24
Lindsay	RoundValley	12	0	0	0	0	0	0	0	0
Maraschino	Roundel	12	3.71	3.46	3	3	3.18	2.81	2.3	1.89
Devers	Rover	12	3.67	3.67	3	3	3.06	2.77	2.18	1.81
Running Springs	Rowco	12	2.35	2.35	2.35	2.35	3.48	3.48	3.4	2.88

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Maxwell	Rowe	12	1.77	1.77	1.77	1.77	3.48	3.48	3.48	3.48
Anita	Rowland	4.16	0	0	0	0	0.7	0	0	0
Stadium	Roxanne	12	0	0	0	0	3.41	3.41	3.41	3.41
Beverly	Roxbury	4.16	0.24	0.24	0.24	0.24	0.78	0.78	0.57	0.48
Liberty	RoyalOaks	12	0	0	0	0	0	0	0	0
Arroyo	Royce	4.16	1.15	0	0	0	1	0	0	0
Naples	Roycroft	4.16	0.31	0	0	0	0.68	0	0	0
Fullerton	Royer	12	0	0	0	0	3.47	3.47	3.47	3.47
Borrego	Rubin	12	0	0	0	0	3.22	2.96	2.37	1.94
Santiago	Ruble	12	2.03	2.03	2.03	2.03	2.37	2.37	2.37	2.37
Limestone	Ruby	12	0	0	0	0	3.49	3.49	3.49	3.49
Huntington Park	Rugby	4.16	0.49	0	0	0	1.17	0	0	0
Smiley	Ruggles	4.16	0.56	0	0	0	0.54	0	0	0
Fogarty	Ruiz	12	5.09	5.09	5.09	3	2.81	2.81	2.81	2.63
Highland	Ruler	12	0	0	0	0	2.92	2.92	2.92	2.66
Johanna	Rummy	12	2.61	2.61	2.61	2.61	0	0	0	0
Culver	Runway	16	3.97	3.97	3.97	3.97	9.74	8.26	6.9	6.37
Garvey	Rural	4.16	0	0	0	0	1.22	0.94	0.64	0.54
Victor	RussBoyd	33	0	0	0	0	0	0	0	0
Broadway	Russell	12	3.04	3.02	3.02	3.02	3.27	3.27	3.27	3.12
O'neill	Rustic	12	0.39	0.39	0.39	0.39	3.19	2.64	2.1	1.77
Crown	Rutgers	12	0	0	0	0	3.34	3.34	2.85	2.42
La Veta	Ruth	12	0	0	0	0	3.48	3.48	3.48	3.48
Brighton	Ruthellen	16	3.97	3.97	3.97	3.97	8.02	6.75	6.1	5.63
Cucamonga	Rutherford	12	3	3	3	3	3.31	3.31	3.31	3.31
Villa Park	Rutledge	12	0.51	0.51	0.51	0.51	3.25	3.25	3.25	3.25
Cucamonga	Ruttman	12	0	0	0	0	3.25	3.25	3.25	3.25
Lennox	Ryan	16	4.58	3.97	3.97	3.97	7.85	6.47	5.85	5.42
Sixteenth Street	Rye	12	3.02	0	0	0	3.43	0	0	0
Ely	Rzyski	12	1.66	1.66	1.66	1.66	3.28	3.28	3.28	3.28
Passons	SHADE	12	0	0	0	0	3.44	3.44	3.44	3.22
Hanford	Saber	12	0	0	0	0	0	0	0	0
Pechanga	Sabino	12	1.26	1.26	1.26	1.26	2.77	2.77	2.77	2.46
Fair Oaks	Sacramento	4.16	0	0	0	0	1.12	0.77	0.6	0.51
Calectric	Sad	33	0	0	0	0	27	27	27	27
Banning	Saddleback	33	11.03	8.38	8.38	8.38	27	26.54	26.54	18.44
Palm Springs	Safeway	4.16	0.31	0	0	0	0.66	0	0	0
Mt. Vernon	Sage	4.16	1.01	1.01	1.01	1.01	1.29	0.61	0.61	0.52
Bryman	Sagebrush	4.16	1	0	0	0	1.19	0	0	0
Zack	Sagehen	12	0	0	0	0	0	0	0	0
Estrella	Sagittarius	12	0	0	0	0	3.3	3.3	3.3	3.25
Torrance	Sago	16	3.74	3.74	3.74	3.74	7	5.9	5.29	4.91
Tamarisk	Saguaro	12	0	0	0	0	0	0	0	0
Santa Rosa	Sahara	12	0	0	0	0	0	0	0	0
Arcadia	SaintJo	16	0	0	0	0	7.42	6.25	5.59	5.19
Slater	Saints	12	3.02	3.02	3.02	3.02	3.25	3.25	2.91	2.45
Fairview	Sakioka	12	4.29	3.02	3.02	3.02	3.48	3.48	3.19	2.7
Bedford	Saks	4.16	0	0	0	0	0.64	0	0	0
Sullivan	Salem	4.16	0.95	0	0	0	0.6	0	0	0
Cudahy	Sales	4.16	0.21	0	0	0	1.27	0	0	0
El Nido	Salmon	16	0	0	0	0	9.4	6.4	5.75	5.34
Three Rivers	SaltCreek	12	0	0	0	0	0	0	0	0
Cudahy	SaltLake	16	5.67	5.67	5.67	5.67	8.42	6.72	6.06	5.6
San Miguel	Salvador	16	3.97	3.97	3.97	3.97	7.02	5.73	5.18	4.79
Layfair	Sam	12	0	0	0	0	3.38	3.38	3.38	2.98
South Gate	Samar	4.16	1.34	0	0	0	1.26	0	0	0
Wimbledon	Sampras	12	5.33	3.02	3.02	3.02	1.09	1.09	1.09	0.94
Modoc	SanAndreas	4.16	0.71	0	0	0	1.2	0.68	0.68	0.57
San Antonio	SanJose	12	6.09	6.09	0	0	3.08	3.08	3.08	3.08
Bryan	SanJuan	12	2.73	2.73	2.73	2.73	3.46	3.46	3.46	3.46
Casitas	SanNicholas	16	4.84	3.97	3.97	3.97	6.16	5.11	4.6	4.27
San Marino	SanPasqual	4.16	0	0	0	0	0.63	0	0	0
Garnet	SanRafael	12	0.8	0.8	0.8	0.8	3.18	3.18	3.02	2.56
Declez	Sanber	12	1.12	1.12	1.12	1.12	3.37	3.37	3.17	2.69
Fernwood	Sanborn	16	3.97	0	0	0	11.09	0	0	0
Southwind	Sancho	12	3.02	0	0	0	0.94	0	0	0
Solemint	SandCanyon	16	0	0	0	0	4.58	3.81	3.45	3.19
Santa Rosa	SandDunes	12	0	0	0	0	0	0	0	0
Randall	Sandell	12	0.93	0.93	0.93	0.93	3	3	3	3
Upland	Sanders	4.16	0	0	0	0	0.61	0	0	0
Tahiti	Sandman	16	9.32	9.32	3.97	3.94	8.73	7.23	6.35	5.9
Felton	Sandra	16	1.37	1.37	1.37	1.37	8.58	7.13	6.45	5.97
Bassett	Sandy	12	2.42	2.42	2.42	2.42	3.4	3.4	3.4	3.4
Duarte	Sanitarium	4.16	0	0	0	0	1.25	0.61	0.48	0.41
Bartolo	Sanka	4.16	0.6	0	0	0	0.71	0	0	0
Hi Desert	Santana	33	15.66	15.66	0	0	0	0	0	0
Padua	Santorini	12	0	0	0	0	2.68	2.68	2.12	1.79
Upland	Sapphire	12	0	0	0	0	3.24	3.24	3.24	2.77
Jefferson	Sapporo	12	1	1	1	1	3.45	3.45	3.45	3.45
Ramona	Sarah	4.16	0	0	0	0	1.25	0.51	0.51	0.42

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Levy	Saratoga	16	3.19	3.19	3.19	3.19	7.28	5.96	5.39	4.99
Octol	Sargent	12	0	0	0	0	0	0	0	0
Broadway	Sassoon	12	0	0	0	0	3.45	3.45	3.45	3.45
San Antonio	Satellite	12	0	0	0	0	2.55	2.55	2.55	2.21
Randolph	Saturn	16	7.93	7.93	7.93	3.97	8.96	7.42	6.94	6.09
Thornhill	Saturnino	12	2.99	2.99	2.99	2.99	0.98	0.98	0.98	0.98
Woodville	Saucelito	12	0	0	0	0	0	0	0	0
Idyllwild	Saunders	12	0.31	0.31	0.31	0.31	3.45	3.45	3.45	3.12
Pepper	Sauterne	12	0.76	0.76	0	0	3.48	3.48	3.48	3.48
Milliken	Sauza	12	2.2	2.2	2.2	2.2	3.49	3.49	3.49	3.15
Canyon	Savi	12	1.14	1.14	1.14	1.14	2.78	2.78	2.43	2.03
Nelson	Savory	12	0.22	0.22	0.22	0.22	0	0	0	0
Inyokern	Sawmill	33	0	0	0	0	0	0	0	0
Arrowhead	Sawpit	33	8.38	0	0	0	27	25.55	23.87	14.22
Somerset	Sawyer	12	1.17	1.17	1.17	1.17	3.47	3.47	3.47	3.47
Garvey	Saxon	4.16	0.05	0	0	0	0.61	0	0	0
Niguel	Saxophone	12	0	0	0	0	3.49	3.49	3.49	2.97
Vail	Saybrook	16	4.89	3.97	3.97	3.97	10.18	7.9	7.12	6.61
Gavilan (115)	Scalp	12	7.1	7.1	3.02	3.02	3.48	3.48	3.48	3.48
Orange	Scarlet	12	0.44	0	0	0	2.89	2.89	2.89	2.89
Columbine	Schenley	12	0	0	0	0	0	0	0	0
Santiago	Schilling	12	0	0	0	0	2.99	2.99	2.99	2.69
Maraschino	Schmidt	12	3.02	3.02	3.02	3.02	3.06	3.06	3.06	2.71
Santa Rosa	Scholar	12	0	0	0	0	0	0	0	0
Alder	Scholl	12	1.91	1.91	1.91	1.91	3.32	3.32	3.25	2.75
Huntington Park	School	4.16	0.84	0	0	0	0.7	0	0	0
Channel Island	Schooner	16	3.97	3.94	3.94	3.94	7	5.91	5.22	4.85
Beverly	Schuyler	4.16	0	0	0	0	0.57	0.57	0.46	0.38
Placentia	Science	12	3.02	0	0	0	3.47	0	0	0
Walteria	Sciurba	16	0.35	0.35	0.35	0.35	6.95	5.84	5.28	4.88
Hamilton	Score	12	3.4	3.02	3.02	3.02	2.96	2.96	2.96	2.8
Estrella	Scorpio	12	1.42	1.42	1.42	1.42	3.47	3.47	3.47	3.47
Scorpion P.T.	Scorpion	12	0	0	0	0	0	0	0	0
Chiquita	Scotch	12	0.63	0.63	0.63	0.63	2.55	2.55	2	1.66
Visalia	Scott	4.16	0	0	0	0	0	0	0	0
Bolsa	Scow	12	2.11	2.11	2.11	2.11	3.37	3.36	2.67	2.23
Johanna	Scrabble	12	2.51	2.51	0	0	3.49	3.49	3.49	3.49
Quartz Hill	Scrapper	12	1.75	1.75	1.75	1.75	2.65	2.65	2.44	2.06
Stadler	Scrimmage	12	2.8	2.8	2.8	2.8	3.18	3.18	3.18	2.52
Tamarisk	Scruboak	12	0	0	0	0	0	0	0	0
El Nido	Seabass	16	1.37	1.37	1.37	1.37	4.39	3.69	3.26	3.01
Carpinteria	Seacliff	16	2.45	2.45	2.45	2.45	5.84	4.91	4.42	4.11
Hesperia	Seaforth	12	0.26	0.26	0.26	0.26	1.31	1.31	1.17	0.98
Milliken	Seagrams	12	0	0	0	0	0	0	0	0
Tahiti	Seahorse	16	13.2	0	0	0	7.38	0	0	0
Victorville	Seals	12	4.39	4.39	4.39	3.02	3.41	3.41	3.2	2.71
Hoyt	Seaman	4.16	0	0	0	0	1.2	0.73	0.57	0.48
Canyon Lake	Searay	12	0	0	0	0	2.44	2.44	2.36	1.98
Pico	Seaside	12	3	0	0	0	3.49	0	0	0
Stadium	Seat	12	2.59	2.59	2.59	2.59	3.44	3.44	3.16	2.67
Wave	Seaweed	12	3.02	3.02	3.02	0	2.55	2.55	2.55	2.55
Triton	Seawolf	12	0	0	0	0	2.09	2.09	1.95	1.63
Rubidoux	Sebastian	4.16	0.48	0	0	0	0.74	0	0	0
Arroyo	Seco	16	2.72	2.72	2.72	2.72	8.8	7.13	6.43	5.93
Beverly	Secretary	16	0	0	0	0	8.94	7.48	6.68	6.19
Santa Monica	Security	4.16	0.38	0	0	0	0.74	0	0	0
Huston	Seeley	2.4	0.24	0.24	0.24	0.24	1.29	0.73	0.57	0.48
Fairview	Segerstrom	12	2.28	2.28	2.28	2.28	3.21	3.21	3.21	3.21
Rosemead	Segovia	16	3.97	3.97	3.97	3.97	8.51	7.12	6.4	5.94
Viejo	Seguro	12	2.72	2.72	2.72	2.72	3.29	3.29	3.29	3.1
Etiwanda	Sellers	12	0	0	0	0	2.78	2.78	2.35	1.95
Victoria	Selva	16	3.36	3.36	3.36	3.36	8.08	6.72	6.03	5.59
Placentia	Semester	12	1.39	0	0	0	3.49	0	0	0
Somis	Seminary	16	3.97	3.97	3.97	3.97	6.61	5.42	4.86	4.51
Gavilan (115)	Seminole	12	0	0	0	0	3.49	0	0	0
Eric	Semora	12	1.59	1.59	1.59	1.59	3.28	3.28	3.28	3.17
Cornuta	Senate	12	0.97	0	0	0	3.48	0	0	0
Cudahy	Senga	4.16	0.73	0.73	0.73	0.73	1.27	0.56	0.56	0.47
Concho	Senorita	12	0	0	0	0	0	0	0	0
Chatham	Sequoia	12	0	0	0	0	0	0	0	0
Concho	Serape	12	0	0	0	0	0	0	0	0
Rivera	Serapis	4.16	0.34	0	0	0	1.27	0.69	0.69	0.58
Bliss	Serenity	12	0	0	0	0	0	0	0	0
Corona	Serfas	12	0	0	0	0	3.41	3.41	3.34	2.78
Pechanga	Serna	12	0	0	0	0	3.16	3.16	2.85	2.41
Crater	Serra	16	3.97	3.97	3.97	3.97	7.33	5.49	5	4.59
Chino	Serranos	12	0.79	0.79	0.79	0.79	3.42	3.42	3.42	3.08
Culver	Servo	4.16	0	0	0	0	0.99	0.54	0.43	0.34
Pioneer	Settler	12	1.66	1.66	1.66	1.66	3.47	3.47	3.47	3.47
Pedley	Sevaine	12	0	0	0	0	2.37	2.37	2.05	1.74

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Bixby	SeventhSt.	4.16	0.46	0	0	0	1.29	0	0	0
Venice Hill	Seville	12	0	0	0	0	0	0	0	0
Hamilton	Sewell	12	1.28	1.28	1.28	1.28	3.13	3.13	3.13	3.13
Saticoy	Sexton	16	2.77	2.77	2.77	2.77	5.53	4.64	4.16	3.86
La Palma	Shadow	12	1.95	1.95	1.95	1.95	3.44	3.44	3.44	3.41
Chino	Shaffer	12	1.59	1.59	1.59	1.59	3.1	3.1	3.1	3.1
Arrowhead	Shake	33	7.7	7.7	7.7	7.7	27	19.56	19.56	19.56
Monrovia	Shamrock	4.16	0.18	0.18	0.18	0.18	1.13	0.7	0.55	0.46
Downs	Shangrila	12	0	0	0	0	0	0	0	0
Gilbert	Shank	12	3.46	3.46	3.02	3.02	3.48	3.48	3.48	3.23
Sunnyside	Sharp	4.16	0	0	0	0	0.6	0	0	0
Tennessee	Shasta	12	4.99	4.99	3.02	3.02	1.18	1.18	1.18	1.18
Hathaway	Shaw	4.16	0.32	0	0	0	0.89	0	0	0
Cantil	Sheep	12	0	0	0	0	0	0	0	0
Hi Desert	Sheephole	33	8.38	8.38	8.38	8.38	0	0	0	0
Carpinteria	Sheffield	16	3.97	3.97	3.97	3.97	5.25	4.4	3.97	3.69
Bandini	Sheila	16	3.97	0	0	0	6.96	0	0	0
Watson	Shell	12	4.7	4.7	4.7	3.02	3.49	3.49	3.49	3.49
Alon	Shelldom	12	3.61	3.61	3.61	3.61	3.49	3.49	3.49	3.49
Potrero	Shenandoah	16	1.76	1.76	1.76	1.76	7.24	6.02	5.47	5.04
Moulton	Shepherd	12	0	0	0	0	2.92	2.92	2.92	2.6
Thornhill	Sheraton	12	0	0	0	0	2.25	2.25	2.18	1.84
Windsor Hills	Sherbourne	16	4.19	3.97	3.97	3.97	7.79	5.81	5.23	4.87
Corona	Sheridan	12	0.28	0.28	0.28	0.28	3.13	3.13	2.93	2.45
Fairfax	Sherman	4.16	0.66	0	0	0	0.91	0	0	0
Pepper	Sherry	12	1.51	1.51	1.51	1.51	3.39	3.39	3.39	3.39
Sherwood P.T.	Sherwood	4.16	0.53	0.53	0.53	0.53	1.29	0.8	0.63	0.53
Indian Wells	Sheryl	12	0	0	0	0	0	0	0	0
Auld	Shetland	12	2.83	2.83	2.83	2.83	2.71	2.71	2.71	2.38
Randall	Shine	12	0.98	0.98	0.98	0.98	3.07	3.07	3.07	2.58
Auld	Shipley	12	2.41	2.41	2.41	2.41	3.23	3.23	3.23	2.69
Lakewood	Shipway	4.16	0.11	0.11	0.11	0.11	0.81	0.33	0.33	0.27
Pepper	Shiraz	12	0	0	0	0	3.27	3.27	3.2	2.71
Oak Grove	Shirk	12	0	0	0	0	0	0	0	0
Anita	Shirley	4.16	0.2	0	0	0	0.62	0	0	0
Capitan	Shoal	16	0	0	0	0	7.7	7.7	6.39	6.39
Arcadia	Shoemaker	16	1.57	1.57	1.57	1.57	7.3	6.44	5.55	5.13
Chiquita	Shooter	12	3.02	0	0	0	3.22	3.22	2.59	2.17
Walnut	Shopper	12	0.68	0.68	0.68	0.68	3.49	3.49	3.49	3.44
Thousand Oaks	Shopping	16	1.69	1.69	1.69	1.69	8.86	6.53	5.96	5.46
Cardiff	Shops	12	0	0	0	0	3.41	3.41	3.08	2.6
Ramona	Shorb	4.16	0.51	0.51	0	0	1.24	0.84	0.67	0.55
Marymount	Shoreline	16	3.97	3.97	3.97	3.97	6.53	5.43	4.91	4.55
Junction	Shoshone	33	3.96	3.96	3.96	3.96	27	6	6	4.37
Center	Shotgun	12	0	0	0	0	3.29	3.29	3.02	2.5
Lawndale	Shoup	4.16	0.53	0	0	0	0.66	0	0	0
Acton	Shovel	12	3.02	3.02	3.02	3.02	2.93	2.16	1.71	1.45
Trophy	Show	12	2.82	2.82	2.82	2.82	3.28	3.28	3.28	2.9
Jersey	Showcase	16	9.56	4.53	4.53	3.97	13.08	6.86	6.86	6.36
Ritter Ranch	Showdown	12	6.29	6.29	3.78	3.78	2.76	2.76	2.65	2.21
Modena	Siam	12	1.12	1.12	1.12	1.12	3.23	3.23	3.23	2.82
Rialto	Sid	12	3.02	3.02	3.02	3.02	3.19	3.19	3.19	3.19
Estero	Sidewinder	16	3.97	3.97	3.97	3.97	6.72	5.45	4.94	4.57
Bryan	Sidney	12	0	0	0	0	3.28	3.28	3.28	3.28
Valdez	Sienna	16	2.96	2.96	2.96	2.96	6.58	5.52	4.95	4.6
Borrego	Siesta	12	1.06	1.06	1.06	1.06	3.47	3.47	3.47	3.35
Carson	Sigma	16	3.8	3.8	3.8	3.8	9.31	7.48	6.73	6.25
Crest	Silicone	16	3.97	3.97	3.97	3.97	6.78	5.63	5.1	4.71
Genamic	Silo	12	1.38	1.38	1.38	1.38	3.07	2.89	2.89	2.42
Randall	Silva	12	0	0	0	0	2.53	2.33	1.89	1.56
Limestone	Silver	12	2.54	2.54	2.54	2.54	2.95	2.95	2.95	2.93
Desert Outpost	SilverMoon	12	7.91	0	0	0	3.17	0	0	0
Cudahy	Silverside	16	0	0	0	0	7.13	5.96	5.34	4.96
Homart	Silvertone	12	0	0	0	0	3.42	3.42	3.42	3.07
Amalia	Simmons	4.16	0.93	0	0	0	1.29	0.69	0.69	0.58
Palmdale	Sims	12	0	0	0	0	2.81	2.81	2.81	2.81
Royal	Sinaloa	16	2.91	2.91	2.91	2.91	6.91	5.64	5.1	4.73
Santa Rosa	Sinatra	33	0	0	0	0	0	0	0	0
Shawnee	Sioux	12	1.49	1.49	1.49	1.49	3.32	3.32	3.32	3.32
Siphon P.T.	Siphon	4.16	0	0	0	0	0	0	0	0
Firehouse	Siren	12	0.78	0.78	0.78	0.78	3.43	3.43	3.43	3.43
Yukon	Sitka	16	3.97	0	0	0	7.34	0	0	0
Skiland	Sitzmark	12	0	0	0	0	0	0	0	0
Santa Monica	SixteenthSt.	4.16	0.97	0	0	0	0.88	0	0	0
Narod	Sizzler	12	0.23	0.23	0.23	0.23	3.33	3.33	3.33	3.09
Farrell	Skelton	12	0.35	0.35	0.35	0.35	2.82	2.82	2.82	2.82
Casa Diablo	Ski	33	0	0	0	0	0	0	0	0
Bolsa	Skiff	12	0	0	0	0	2.99	2.99	2.99	2.99
Terra Bella	Skinkle	12	0	0	0	0	0	0	0	0
Auld	Skinner	33	16.77	16.77	16.77	8.38	27	21.99	21.99	14.07

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Pico	Skipper	12	2.96	0	0	0	3.49	0	0	0
Lucerne	SkyHi	12	1.3	1.3	1.3	1.3	2.52	2.08	1.62	1.37
Skyborne P.T.	Skyborne	12	3.7	0	0	0	3.44	0	0	0
Gisler	Skylab	12	0.8	0.8	0.8	0.8	3.49	3.49	3.49	3.49
Huston	Skyland	2.4	0.11	0	0	0	0.65	0	0	0
Fairview	Skypark	12	1.2	1.2	1.2	1.2	3.49	3.49	3.49	3.49
Shuttle	Skywalker	12	1.15	1.15	1.15	1.15	1.75	1.75	1.75	1.45
Hoyt	Slack	4.16	0.46	0.46	0	0	1.29	1.16	0.7	0.59
Mariposa	Slade	12	0	0	0	0	0	0	0	0
Skiland	Slalom	12	0	0	0	0	0	0	0	0
Limestone	Slate	12	6.59	3.02	3.02	3.02	2.29	2.29	2.29	2.29
Gilbert	Slice	12	0.82	0.82	0.82	0.82	3.2	3.2	3.2	3.2
Chiquita	Sling	12	1.7	1.7	1.7	0	3.13	3.13	3.13	2.58
Compton	Sloan	4.16	1.01	0	0	0	0.81	0	0	0
Minaret	Slope	12	0	0	0	0	0	0	0	0
Bloomington	Slover	12	1.86	1.86	1.86	1.86	2.93	2.93	2.93	2.91
Aqueduct	Sluice	12	0.88	0.88	0.88	0.88	3.44	3.44	3.44	3.09
Oceanview	Smeltzer	12	2.78	2.78	2.78	2.78	3.24	3.24	3.24	3.24
Milliken	Smirnoff	12	1.02	1.02	1.02	1.02	2.39	2.39	2.39	2.17
Vail	Smith	16	3.01	3.01	3.01	3.01	12.7	7.01	6.28	5.83
Olympic	Smithwood	4.16	0	0	0	0	1.05	0	0	0
Twentynine Palms	SmokeTree	12	3.46	3.02	3.02	3.02	3.44	3.44	3.44	3.04
Barre	Snapdragon	12	1.54	0	0	0	3.49	3.05	3.05	3.05
Lafayette	Snead	12	1.21	1.21	1.21	1.21	3.39	3.28	2.62	2.2
Cucamonga	Sneva	12	2.29	2.29	2.29	2.29	3.02	3.02	2.67	2.23
Pedley	Snipes	12	0.81	0.81	0.81	0.81	2.71	2.71	2.71	2.71
Big Creek 2	SnoCat	12	0	0	0	0	0	0	0	0
Running Springs	SnowValley	12	3.02	3.02	3.02	3.02	3.48	3.34	2.79	2.25
Snowcreek P.T.	Snowcreek	12	2.06	0	0	0	3.18	0	0	0
Del Sur	Snowden	12	3.02	3.02	3.02	3.02	0	0	0	0
Minaret	Snowdrift	12	0	0	0	0	0	0	0	0
Alessandro	Snyder	12	2.07	2.07	2.07	2.07	3.44	3.44	3.44	3.44
Manhattan	SoStrand	4.16	0.51	0	0	0	0.82	0	0	0
Indian Wells	Soboba	12	0	0	0	0	0	0	0	0
Telegraph	Socrates	12	1.17	1.17	1.17	1.17	3.2	3.2	3.03	2.57
Boxwood	SodaSprings	12	0	0	0	0	0	0	0	0
La Palma	Soho	12	0	0	0	0	3.49	3.49	3.49	3.49
Modoc	Sola	4.16	1.01	0	0	0	0.6	0	0	0
Bunker	Soldier	12	1.97	1.97	1.97	1.97	3.17	3.17	3.17	2.79
Repetto	Soledad	16	2.32	2.32	2.32	2.32	10.05	7.17	6.45	5.99
Johanna	Solitaire	12	1.93	1.93	1.93	1.93	2.7	2.67	2.14	1.8
Concho	Sombrero	12	0	0	0	0	0	0	0	0
Team	Sonics	12	0.13	0.13	0.13	0.13	3.21	3.21	3.21	3.21
Valley	Sonoma	12	2.04	2.04	2.04	2.04	2.98	2.88	2.37	1.93
Soper P. T.	Soper	4.16	0.11	0	0	0	0.92	0	0	0
Stetson	Sopwith	12	3.02	0	0	0	3.46	3.46	3.46	3.46
Valdez	Sorrento	16	4.43	3.97	3.97	3.97	13.19	7.48	6.67	6.16
Hathaway	Soto	12	0.8	0.8	0.8	0.8	3.37	3.37	3.37	3.37
Southridge P.T.	Southridge	4.16	0.37	0	0	0	0.7	0	0	0
Thornhill	Spa	12	0	0	0	0	3.45	3.45	3.45	3.45
Ganesha	Spadra	12	0	0	0	0	3.45	3.45	3.45	3.45
Citrus	Spanada	12	0	0	0	0	2.98	2.98	2.98	2.62
Highland	Sparks	12	1.27	1.27	1.27	1.27	3.2	3.2	3.2	2.85
Tennessee	Sparling	12	0.83	0.83	0.83	0.83	2.9	2.9	2.9	2.5
Talbert	Sparrow	12	1.15	0	0	0	3.49	0	0	0
Carson	Sparton	16	4.79	3.97	3.97	3.97	8.02	6.93	5.96	5.54
Linden	Spaulding	4.16	0.87	0	0	0	0.63	0	0	0
Hamilton	Speaker	12	3.02	0	0	0	3.49	0	0	0
Apple Valley	Spear	12	0	0	0	0	0	0	0	0
Chino	Spectrum	12	0	0	0	0	3.39	3.39	3.38	2.87
Declez	Speedway	12	0	0	0	0	0	0	0	0
Friendly Hills	Spencer	4.16	0.41	0	0	0	0.58	0	0	0
Hinkley	Speth	12	0	0	0	0	0	0	0	0
San Bernardino	Sphinx	12	3.22	3.22	3	3	3.48	3.48	3.13	2.65
Moreno	Spice	12	0.8	0.8	0.8	0.8	3.15	3.15	3.15	2.98
Bloomington	Spike	12	2.43	2.43	2.43	2.43	3.14	3.14	2.95	2.5
Rio Hondo	Spillway	16	2.61	2.61	2.61	2.61	7.4	6.1	5.5	5.11
Topaz	Spinel	4.16	0.38	0	0	0	0.65	0	0	0
Duarte	Spinks	4.16	0.05	0.05	0.05	0.05	1.19	0.73	0.6	0.49
Channel Island	Spinnaker	16	3.57	3.57	3.57	3.57	7.1	5.9	5.33	4.95
Lennox	Spinning	4.16	0.67	0.67	0.67	0.67	1.12	0.55	0.55	0.41
Stetson	Spitfire	12	0.85	0.85	0.85	0.85	3.46	3.46	3.46	3.46
Newbury	Splendor	16	0.56	0.56	0.56	0.56	8.2	5.63	5.63	5.16
Carmenita	Splendora	12	0	0	0	0	3.45	3.45	3.45	3.45
Minaret	Sportsman	12	0	0	0	0	0	0	0	0
Mayberry	Sprague	12	0.86	0.86	0.86	0.86	2.91	2.78	2.2	1.86
Seabright	Spray	12	3.02	0	0	0	3.49	0	0	0
Signal Hill	Spring	12	1.99	1.99	1.99	1.99	3.44	3.44	3.44	3.44
Savage	SpringValley	12	0.2	0.2	0.2	0.2	3.01	2.71	2.17	1.82
Trophy	Sprint	12	0	0	0	0	2.97	2.97	2.77	2.28

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Navy Mole	Spruance	12	3.02	0	0	0	3.49	0	0	0
Montebello	Spruce	4.16	0	0	0	0	1.25	0.89	0.69	0.58
Palmdale	Spur	12	2.56	2.56	2.56	2.56	3.35	3.35	3.35	2.92
Hanford	Squadron	12	0	0	0	0	0	0	0	0
Neptune	Squall	12	5.27	5.27	3.02	3.02	3.44	3.44	3.44	3.23
Arrowhead	Squint	12	3.77	3.02	3.02	3.02	3.41	3.41	3.23	2.72
Bedford	Squires	4.16	0.21	0	0	0	0.67	0	0	0
Modena	SriLanka	12	2.1	2.1	0	0	3.14	3.14	2.56	2.11
Alhambra	St.Charles	16	0.34	0.34	0.34	0.34	8.42	6.71	5.88	5.46
Bryan	St.Croix	12	0	0	0	0	3.47	3.47	3.47	3.47
Venice Hill	St.Johns	12	0	0	0	0	0	0	0	0
Bryan	St.Thomas	12	3.3	3.3	3.02	3.02	3.37	3.37	3.37	3.37
Palm Canyon	Stack	12	2.89	2.89	2.89	2.89	3.41	3.41	3.41	3.41
Felton	Stacy	4.16	0.92	0	0	0	0.59	0	0	0
Puente	Stafford	12	1.53	1.53	1.53	1.53	3.45	3.45	3.45	3.36
Carmenita	Stage	12	0.29	0.29	0.29	0.29	3.49	3.49	3.49	3.49
Ivyglen	Stageline	12	0.51	0.51	0.51	0.51	3.05	3.05	2.44	2.05
Bain	Staghorn	12	3.34	3.34	3.02	3.02	3.42	3.42	3.42	3.42
Peyton	Stalling	12	0	0	0	0	2.96	2.96	2.96	2.21
Gallatin	Stamper	12	1.58	1.58	1.58	1.58	1.31	1.31	1.31	1.21
Oceanview	Standard	12	0.41	0.41	0.41	0.41	3.2	3.2	3.11	2.63
Rancho	StandingRock	12	0.49	0.49	0.49	0.49	0	0	0	0
Mayflower	Standish	4.16	0	0	0	0	0.58	0	0	0
Mayberry	Stanford	12	0	0	0	0	3.01	3.01	2.65	2.23
Santa Barbara	Stanwood	16	2.46	2.46	2.46	2.46	6.57	5.41	4.89	4.54
Canyon	StarRock	12	0.48	0.48	0.48	0.48	2.85	2.85	2.5	2.09
Neptune	Starboard	12	4.87	3.46	3.02	3.02	3.33	3.33	3.33	3.33
Santa Fe Springs	Starbuck	12	2.46	2.46	2.46	2.46	3.48	3.48	3.48	3.48
Lockheed	Starfighter	16	0.22	0.22	0.22	0.22	4.64	3.85	3.48	3.22
Estrella	Stargazer	12	0	0	0	0	3.34	3.34	3.34	3.34
Cajalco	Starglow	12	0	0	0	0	2.84	2.42	1.91	1.62
Walteria	Statler	16	2.41	2.41	2.41	2.41	6.43	5.12	4.61	4.29
Oasis	Stealth	12	0	0	0	0	0	0	0	0
Seabright	Steam	12	3.02	3.02	0	0	3.49	3.49	3.49	3.49
Santa Susana	Stearns	16	0	0	0	0	7.49	6.41	5.7	5.27
Ridgeview P.T.	Steel	12	2.84	2.84	2.84	2.84	3.42	3.42	2.66	2.24
Liberty	Steelman	12	0	0	0	0	0	0	0	0
Del Rosa	Stegman	12	1.56	1.56	1.56	1.56	3.47	3.47	3.47	3.47
Marion	Stella	12	3.4	3.4	3.02	3.02	3.16	3.16	2.96	2.51
Tippecanoe	Sterling	4.16	0.36	0	0	0	0.87	0	0	0
Clark	Stevely	4.16	0	0	0	0	0.93	0.44	0.35	0.29
Culver	Stevens	4.16	0.3	0.3	0.3	0.3	0.73	0.43	0.32	0.27
Big Creek 2	Stevenson	12	0	0	0	0	0	0	0	0
Beaumont	Stewart	4.16	0.27	0	0	0	0.62	0	0	0
Cucamonga	Stig	12	0	0	0	0	3.49	3.49	3.49	3.17
Dryden P.T.	Stillwater	12	0	0	0	0	3.49	0	0	0
MacArthur	Stillwell	12	0	0	0	0	3.29	3.29	3.29	3.01
Palmdale	Sting	12	0	0	0	0	2.48	2.48	2.48	2.48
Chiquita	Stinger	12	2.97	2.97	2.97	2.97	3.4	3.4	3.4	3.33
Lighthipe	Stitzer	12	0.35	0.35	0.35	0.35	3.25	3.25	3.25	3.25
Gallatin	Stoakes	12	0	0	0	0	3.48	0	0	0
Alon	Stocco	12	1.31	1.31	1.31	1.31	3.15	3.15	3.15	3.15
Bloomington	Stockcar	12	0	0	0	0	2.97	2.97	2.92	2.47
Windsor Hills	Stocker	16	3.97	3.97	3.97	3.97	6.97	5.83	5.27	4.89
Hanford	Stockton	12	0	0	0	0	0	0	0	0
Compton	Stockwell	4.16	0.32	0	0	0	0.67	0	0	0
Milliken	Stoli	12	0	0	0	0	3.46	3.46	3.46	3.46
Columbine	Stone	12	0	0	0	0	0	0	0	0
Ravendale	Stoneley	16	0	0	0	0	7.94	6.98	6.07	5.58
Skylark	Stoneman	12	3.46	3.46	3.02	3.02	3.18	3.12	2.4	2.04
Yucaipa	Stonewood	12	0	0	0	0	2.66	2.43	1.99	1.62
Etiwanda	Stooges	12	1.33	1.33	1.33	1.33	3.25	3.25	3.25	3.25
Chino	Storage	12	3.35	3.02	3.02	3.02	3.09	3.09	3.09	3.09
Outlet P.T.	Stores	12	1.36	1.36	1.36	1.36	3.35	3.35	3.35	3.18
Vegas	Storke	16	1.35	1.35	1.35	1.35	8	6.45	5.81	5.4
Neptune	Storm	12	2.78	2.78	2.78	2.78	3.12	3.12	3.12	2.93
Granada	Story	4.16	0	0	0	0	1.23	0.81	0.65	0.54
Chiquita	Stout	12	3.27	3.02	3.02	3.02	3.16	3.16	3.11	2.41
Moorpark	Strathern	16	0.11	0.11	0.11	0.11	6.41	5.58	4.86	4.51
Perry	Strawberry	4.16	1.01	0	0	0	0.9	0	0	0
Bloomington	Streamliner	12	1.85	1.85	1.85	1.85	3.24	3.24	3.17	2.65
Bridge	Stringer	4.16	0.29	0.29	0.29	0.29	1.22	0.84	0.66	0.56
Auld	Striper	33	23.97	23.97	23.97	23.97	27	27	27	22.37
Stroh P.T.	Stroh	4.16	1.4	0	0	0	1.16	0	0	0
Bridgeport	Strosnider	16	0	0	0	0	0	0	0	0
Banning	Stubby	33	8.38	8.38	8.38	0	27	24.2	15.6	11.84
Carmenita	Studebaker	12	0.73	0.73	0.73	0.73	2.3	2.3	2.3	2.3
Placentia	Student	12	0	0	0	0	3.29	3.29	3.29	3.29
Bliss	Sturgeon	12	0	0	0	0	0	0	0	0
Narrows	Stutz	12	0.06	0.06	0.06	0.06	3.23	3.23	3.23	2.82

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Anaverde	Subida	12	0	0	0	0	3.2	3.2	2.97	2.51
Railroad	Subway	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.23
Porterville	Success	12	0	0	0	0	0	0	0	0
Modena	Sudan	12	4.62	4.62	4.62	3.02	3.28	3.28	3.28	3.14
Sullivan	Sugar	12	0.83	0.83	0.83	0.83	2.93	2.93	2.93	2.93
Sullivan	Sully	12	1.7	1.7	1.7	1.7	3.48	3.48	3.48	3.48
Tamarisk	Sumac	12	0	0	0	0	0	0	0	0
Windsor Hills	Summerhill	16	5.43	3.97	3.97	3.97	8.3	6.76	6.08	5.65
Haveda	Sump	4.16	1.01	0	0	0	1.25	0	0	0
Stoddard	Sun	4.16	0	0	0	0	1.29	0	0	0
Little Rock	SunVillage	12	1.47	1.47	1.47	1.47	0	0	0	0
Felton	Sundale	4.16	1.01	0	0	0	0.69	0	0	0
Sun City	Sundance	12	0	0	0	0	2.56	2.43	1.96	1.63
Helendale	Sundown	12	0.79	0.79	0.79	0.79	0	0	0	0
Hi Desert	Sunfair	25	2.75	2.75	2.75	2.75	3.39	3.39	3.39	3.39
Fairview	Sunflower	12	1.97	1.97	1.97	1.97	3.49	3.49	3.49	3.49
Sun City	Sunglasses	12	3.9	3.78	3.02	3.02	3.34	3.34	3.34	3.34
Rivera	Sunglow	4.16	0.04	0.04	0.04	0.04	1.21	0.6	0.6	0.5
Citrus	Sunkist	12	3.02	0	0	0	3.25	0	0	0
Cathedral City	SunnyLane	4.8	1.26	1.26	1.26	1.26	1.19	0.9	0.74	0.52
Victor	SunnyVista	33	0	0	0	0	27	27	22.57	17.79
San Gabriel	Sunnyslope	4.16	0.01	0	0	0	0.68	0	0	0
Carodean	Sunnyvale	12	0	0	0	0	3.49	0	0	0
Poplar	Sunset	12	0	0	0	0	0	0	0	0
San Antonio	Sunsweet	12	0	0	0	0	2.58	2.58	2.58	2.58
Belding	Suntan	4.16	0	0	0	0	0.58	0	0	0
Santa Monica	Suntower	16	0.15	0	0	0	8.85	7.11	6.27	5.81
Watson	Superior	12	2.39	2.39	2.39	2.39	3.45	3.45	3.45	3.45
Ganesha	Supreme	12	0	0	0	0	3.38	3.38	3.38	3.38
Santa Monica	Surfrider	16	3.97	0	0	0	7.82	0	0	0
Channel Island	Surfside	16	3.05	3.05	3.05	3.05	7.55	5.71	5.14	4.77
Timoteo	Surgeon	12	1.47	1.47	1.47	1.47	3.34	3.34	3.34	2.88
Tipton	Surprise	12	0	0	0	0	0	0	0	0
Surrey U.G.S.	Surrey	4.16	1.01	0	0	0	0.89	0	0	0
Gisler	Surveyor	12	4.11	4.11	4.11	3.02	3.48	3.48	3.48	3.48
Alder	Susan	12	0	0	0	0	2.69	2.69	2.42	2.06
Riverway	Susquehanna	12	0	0	0	0	0	0	0	0
Lawndale	Sutro	4.16	1.01	0	0	0	0.84	0	0	0
Del Rosa	Sutt	12	1.57	1.57	1.57	1.57	3.09	3.09	2.92	2.48
Puente	Suzy	12	0.01	0.01	0.01	0.01	2.36	2.36	2.36	2.36
Tulare	Swall	12	0	0	0	0	0	0	0	0
Delano	Swanson	12	0	0	0	0	0	0	0	0
Hanford	Swatzke	12	0	0	0	0	0	0	0	0
Shandin	Sweetwater	12	0.7	0.7	0.7	0.7	3.34	3.34	3.34	2.95
Fairfax	Sweetzer	4.16	0.03	0	0	0	0.91	0	0	0
Montecito	Swift	4.16	0.35	0.35	0	0	0.99	0.72	0.53	0.45
Archibald	Swiss	12	0	0	0	0	1.83	1.83	1.53	1.29
Visalia	Swoose	12	0	0	0	0	0	0	0	0
Redlands	Sylvan	4.16	0.92	0.92	0.92	0.92	1.21	0.64	0.53	0.42
Topanga	Sylvia	4.16	1.01	0	0	0	1.11	0.62	0.49	0.41
Rancho	Symeron	12	1.81	1.81	1.81	1.81	2.34	2.34	1.9	1.59
Concho	Taberna	12	0	0	0	0	0	0	0	0
Holiday	Tachevah	4.16	1.16	0	0	0	0.64	0	0	0
Stadler	Tackle	12	0	0	0	0	0	0	0	0
Fairview	Tacoma	12	1.1	0	0	0	3.48	0	0	0
Colorado	Taft	16	4.14	4.14	3.94	3.94	9.86	7.95	6.83	6.34
Running Springs	Taggert	12	3.02	3.02	3.02	3.02	3.49	3.49	3.38	2.87
Goshen	Tagus	12	0	0	0	0	0	0	0	0
Tahquitz P.T.	Tahquitz	12	0.32	0.32	0.32	0.32	3.44	3.2	3.2	2.34
Modena	Taiwan	12	0	0	0	0	2.63	1.92	1.49	1.26
Alhambra	Takning	16	0	0	0	0	7.58	6.67	5.74	5.34
Indian Wells	Takota	12	0	0	0	0	0	0	0	0
Dunn Siding	Talc	12	0	0	0	0	0	0	0	0
Perry	Talent	4.16	0.68	0.68	0.68	0.68	1.28	0.83	0.65	0.55
Thousand Oaks	Talley	16	0	0	0	0	5.54	4.58	4.13	3.84
Savage	Talpa	12	1.4	1.4	1.4	1.4	3.29	3.29	2.92	2.47
Tortilla	Tamale	12	0	0	0	0	0	0	0	0
Alder	Tamarind	12	0.53	0.53	0.53	0.53	3.39	3.39	3.39	2.96
Elizabeth Lake	Tambourine	16	2.14	2.14	2.14	2.14	5.91	5.1	4.48	4.15
Bandini	Tammy	16	9.89	3.97	3.97	3.97	9.37	7.95	7.17	6.6
Rush	Tamora	16	0.13	0.13	0.13	0.13	9.35	7.82	6.57	6.11
Cardiff	Tampico	12	2.55	2.55	2.55	2.55	3.45	3.45	3.45	3.18
Ravendale	Tamworth	4.16	0.15	0	0	0	1.11	0	0	0
Orange	Tan	12	3.12	3.02	3.02	3.02	3.01	3.01	3.01	3.01
Walteria	Tandem	16	0.14	0.14	0.14	0.14	7.91	6.65	5.98	5.53
Citrus	Tangerine	12	3.02	3.02	3.02	3.02	3.42	3.42	3.42	3.42
Santa Rosa	Tanglewood	12	0	0	0	0	0	0	0	0
Allen	Tanoble	4.16	0	0	0	0	0.97	0.59	0.45	0.38
Fremont	Taper	4.16	0.81	0.81	0.81	0.81	1.25	0.72	0.59	0.48
Santa Susana	Tapo	16	3.67	3.67	3.67	3.67	5.86	4.92	4.44	4.12

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Lancaster	Target	12	1.7	1.7	1.7	1.7	3.27	3.27	3.27	3.27
Bayside	Tarpon	12	0	0	0	0	3.42	3.42	3.42	2.95
Beverly	Tartar	16	3.97	3.97	3.97	3.97	6.52	6.52	5.82	5.37
Venice Hill	Tarusa	12	0	0	0	0	0	0	0	0
Tatanka P.T.	Tatanka	4.16	0.94	0	0	0	0.82	0	0	0
Center	Tattoo	12	1.94	0	0	0	3.43	0	0	0
Estrella	Taurus	12	0.7	0.7	0.7	0.7	3.49	3.49	3.49	3.49
Cajalco	Tava	12	2.02	2.02	2.02	2.02	2.53	2.43	2.04	1.64
Visalia	Taylor	12	0	0	0	0	0	0	0	0
Placentia	Teacher	12	1.4	1.4	1.4	1.4	2.98	2.98	2.98	2.98
Torrance	Teak	16	3.97	3.97	3.97	3.97	10.4	7.73	7.04	6.48
Porterville	Teapot	12	0	0	0	0	0	0	0	0
Vegas	Tecolote	16	3.97	3.97	3.97	3.97	7.3	6.11	5.52	5.12
Gilbert	Tee	12	4.85	4.85	3.02	3.02	3.43	3.43	3.43	3.13
Havilah	TeeVee	12	1.6	1.6	1.6	1.6	3.49	3.49	2.82	2.82
Neenach	Tejon	12	1.2	1.2	1.2	1.2	0	0	0	0
Francis	Telephone	12	0	0	0	0	3.33	3.33	3.33	3.13
Cabrillo	Teller	12	2.16	0	0	0	2.62	2.62	2.62	2.24
Pierpont	Teloma	4.16	1.01	1.01	1.01	1.01	0.92	0.63	0.46	0.39
Rosemead	Telstar	16	0	0	0	0	8.34	6.73	6.03	5.6
Moraga	Temeck	12	1.01	1.01	1.01	1.01	2.35	2.35	2	1.68
Belmont	Temple	4.16	0	0	0	0	0.62	0	0	0
Woodruff	TenPin	4.16	0.32	0.32	0.32	0.32	1.21	0.54	0.54	0.46
Bloomington	Tender	12	3.31	3.31	3.02	3	1.98	1.98	1.9	1.6
Frazier Park	Tenneco	12	2.4	2.4	2.4	2.4	2.78	1.88	1.49	1.26
Perry	Tenor	4.16	0.35	0.35	0.35	0.35	1.16	0.49	0.49	0.42
Placentia	Term	12	0.73	0.73	0.73	0.73	3.24	3.24	3.24	3.24
Dike	Terminal	12	7.67	0	0	0	3.49	0	0	0
Lemon Cove	Terminus	12	0	0	0	0	0	0	0	0
Archline	Terra	12	2.32	2.32	2.32	2.32	3.38	3.38	3.38	3.38
Elsinore	TerraCotta	33	8.38	8.38	8.38	8.38	27	18.21	14.23	10.35
Passons	Terradell	12	0	0	0	0	3.45	3.45	3.45	3.01
Palos Verdes	Terrazzo	4.16	0.46	0.46	0.46	0.46	1.14	0.63	0.5	0.42
Moulton	Terrier	12	0	0	0	0	2.78	2.78	2.55	2.14
Stadium	Terry	12	3.02	3.02	3.02	3.02	2.88	2.88	2.88	2.49
Corona	Tesoro	12	0	0	0	0	3.35	3.35	2.76	2.33
Alhambra	Test	16	0	0	0	0	7.51	6.24	5.65	5.24
Viejo	Testarudo	12	0.34	0.34	0.34	0.34	3.28	3.28	3.28	3.28
Huston	Tetley	12	2.91	2.91	2.91	2.91	3.47	2.85	2.3	1.89
Johanna	Tetris	12	2.72	0	0	0	3.35	3.35	3.35	3.02
Stadium	Tevis	12	1.02	1.02	1.02	1.02	3	3	3	2.99
Center	Texas	12	0.48	0.48	0.48	0.48	3.48	3.48	3.48	3.32
Glen Avon	Texfi	12	1.99	1.99	1.99	1.99	2.72	2.72	2.72	2.72
Ojai	Thacher	16	1.63	1.63	1.63	1.63	3.4	2.87	2.57	2.39
Rio Hondo	Thames	12	2.16	2.16	2.16	2.16	2.47	2.47	2.33	1.98
Laguna Bell	Theater	16	3.97	3.97	3.97	3.97	8.03	6.76	6.09	5.66
La Veta	Thelma	12	2.46	0	0	0	3.42	3.42	3.42	3.42
Bandini	Thermador	16	8.63	8.63	8.63	4.96	9.53	7.72	6.95	6.45
Pomona	Thomas	4.16	0	0	0	0	1.13	0.73	0.58	0.49
Highland	Thompsen	12	0	0	0	0	2.02	2.02	1.66	1.38
Francis	Thor	12	0	0	0	0	3.25	3.25	3.25	3.25
Palmdale	Thornburg	12	2.73	2.73	2.73	2.73	3.45	3.45	3.45	3.37
Mayberry	Thornton	12	1.15	1.15	1.15	1.15	3.06	3.06	3.06	2.81
Auld	Thoroughbred	12	0.58	0.58	0.58	0.58	1.36	1.36	1.12	0.95
Cypress	Thorpe	12	1.28	0	0	0	3.33	0	0	0
Triton	Thresher	12	1.62	0	0	0	2.62	2.62	2.51	2.1
Wrightwood	Thrush	2.4	0.04	0.04	0.04	0.04	1.22	0.82	0.65	0.54
Oasis	Thunderbolt	12	4.15	0	0	0	0.36	0.36	0.29	0.24
Fremont	Tichenor	16	5.44	3.97	3.97	3.97	7.42	6.27	5.6	5.21
Stadium	Ticket	12	3.02	3.02	3.02	3.02	3.34	3.34	3.34	3.34
Casitas	Tico	16	2.06	2.06	2.06	2.06	5.7	4.65	4.19	3.9
Lucas	Tide	4.16	0.35	0	0	0	1.07	0.58	0.58	0.48
Cortez	Tienda	12	0.05	0.05	0.05	0.05	3.43	3.43	3.43	3.41
Little Rock	TierraBonita	12	1.66	1.66	1.66	1.66	0	0	0	0
Center	Tiger	12	1.66	1.66	1.66	1.66	3.45	3.45	3.45	3.45
Rio Hondo	Tigris	12	1.67	1.67	1.67	1.67	3.44	3.44	3.35	2.84
Wimbledon	Tilden	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Narod	Tile	12	1.58	1.58	1.58	1.58	3.17	3.17	3.17	3.09
Fillmore	TimberCanyon	16	3.94	3.94	3.94	3.94	2.13	1.79	1.61	1.5
Lucerne	Timco	12	1.74	1.74	1.74	1.74	3.24	2.51	1.95	1.65
Sierra Madre	Times	4.16	0.26	0.26	0.26	0.26	0.55	0.55	0.5	0.37
Niguel	Timpani	12	0.33	0.33	0.33	0.33	3.22	3.22	2.75	2.33
Limestone	Tin	12	1.81	1.81	1.81	1.81	3.34	3.34	3.34	3.34
El Sobrante	TinMine	12	3.65	3.65	3.65	3.02	3.49	3.49	3.26	2.75
Hamilton	Tinker	12	5.04	3.02	3.02	3.02	3.27	3.27	3.27	2.72
Murphy	Tipperary	12	3.02	0	0	0	3.47	0	0	0
Saugus	Tips	16	4.53	3.97	3.97	3.97	7.66	6.4	5.68	5.28
Estero	Tiros	16	3.97	3.97	3.97	3.97	4.51	3.78	3.41	3.17
Little Rock	Titan	12	2	2	2	2	0	0	0	0
Camden	Titanium	12	3.02	3.02	3.02	3	3.29	3.29	3.29	3.25

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Brookhurst	Tittle	12	0	0	0	0	3.26	3.26	3.26	3.26
Peyton	Titus	12	0	0	0	0	2	2	2	1.95
Mt. Wilson	Tivo	16	7.65	7.65	7.65	7.65	8.75	7.4	6.63	6.15
Los Cerritos	Tizzard	12	3.02	0	0	0	3.47	0	0	0
Liberty	Tlsmith	12	0	0	0	0	0	0	0	0
Del Amo	Toblerone	12	0	0	0	0	3.49	3.49	3.49	3.49
Haskell	Toga	16	0.92	0.92	0.92	0.92	7.49	6.3	5.56	5.17
Declez	Tokay	12	0.29	0.29	0.29	0.29	3.41	3.41	3.12	2.64
Arroyo	Tola	16	4.26	4.26	3.97	3.97	7.52	6.25	5.65	5.24
Santiago	Tolar	12	0	0	0	0	3.49	3.49	3.21	2.71
Naples	Toledo	4.16	0.28	0	0	0	0.72	0	0	0
Whitewater	Toll	4.16	0.32	0.32	0.32	0.32	0.8	0.52	0.42	0.33
Tollhouse P.T.	Tollhouse	4.16	0	0	0	0	0	0	0	0
Indian Wells	Toltec	12	0	0	0	0	0	0	0	0
Chase	Tolton	12	0	0	0	0	2.97	2.97	2.97	2.97
Monolith	Tomahawk	12	2.63	2.63	2.63	2.63	3.37	3.37	2.71	2.3
Oasis	Tomcat	12	1.76	1.76	1.76	1.76	0	0	0	0
Merced	Tommy	12	0.1	0.1	0.1	0.1	3.2	3.2	3.13	2.63
Palm Village	Ton	12	0	0	0	0	0	0	0	0
Milliken	Tonic	12	4.12	4.12	3.02	3.02	3.49	3.49	3.49	3.11
La Habra	Tonner	12	0.21	0.21	0.21	0.21	3.31	3.31	2.82	2.36
Apple Valley	Tonto	12	1.84	1.84	1.84	1.84	2.82	2.82	2.37	2
Industry	Tool	12	0	0	0	0	3.47	0	0	0
Rivera	Topeka	4.16	0	0	0	0	0.86	0	0	0
Landing	Topoc	16	3.53	3.53	3.53	3.53	6.05	5.07	4.58	4.24
Bassett	Torchlight	12	1.11	1.11	1.11	1.11	3.1	3.1	3.1	3.1
Las Lomas	Torino	12	0	0	0	0	3.46	3.46	3.46	3.17
Yorba Linda	Tornado	12	0.66	0.66	0.66	0.66	2.98	2.98	2.98	2.98
Canadian P.T.	Toronto	12	3.02	3.02	3.02	3.02	3.48	3.48	2.96	2.45
Narrows	Torpedo	12	1.2	1.2	0	0	3.48	3.48	3.48	3.48
Yorba Linda	Torrent	12	0.76	0.76	0.76	0.76	3.04	3.04	3.04	3.04
Santa Rosa	TorroPeak	33	0	0	0	0	0	0	0	0
Carson	Torson	16	3.49	3.49	3.49	3.49	7.49	6.35	5.65	5.24
Farrell	Tortuga	12	2.26	2.26	2.26	2.26	1.6	1.6	1.6	1.44
Washington	Touchdown	12	2.33	2.33	2.33	2.33	3.41	3.41	3.41	3.3
Topaz	Tourmaline	4.16	0	0	0	0	0.9	0.61	0.49	0.41
Gilbert	Tourney	12	1	1	1	1	3.4	3.4	3.4	3.4
Ganesha	Tower	4.16	0.19	0.19	0	0	1.26	0.88	0.7	0.58
Garnet	Townhall	33	8.07	8.07	8.07	8.07	0	0	0	0
Potrero	Townsgate	16	3.55	3.55	3.55	3.55	6.97	5.61	5.08	4.69
Santa Susana	Township	16	0	0	0	0	9.33	5.26	4.74	4.39
Keeler P.T.	Townsite	2.4	0	0	0	0	0	0	0	0
Lindsay	Towt	4.16	0	0	0	0	0	0	0	0
Cherry	Toyon	12	8.91	8.91	3.02	3.02	3.49	3.49	3.49	3.49
Irvine	Trabuco	12	0	0	0	0	3.24	3.24	2.72	2.29
Michillinda	Track	4.16	0	0	0	0	1.25	0.67	0.67	0.57
Declez	Tractor	12	3.02	3.02	3.02	3.02	3.48	3.48	3.48	3
Santa Monica	Tradewind	16	3.97	3.97	3.97	3.97	8.41	6.38	5.75	5.34
Mascot	Trailblazer	12	0	0	0	0	0	0	0	0
Railroad	Train	12	0	0	0	0	3.13	3.13	2.85	2.4
Garnet	Tram	33	8.38	8.38	8.38	8.38	0	0	0	0
Cathedral City	Tramview	4.8	0.63	0	0	0	1.05	0	0	0
Fruitland	Transit	16	2.46	2.46	2.46	2.46	7.14	5.45	4.93	4.57
Ditmar	Transplant	4.16	0	0	0	0	0.99	0.44	0.44	0.37
Alder	Trapp	12	0	0	0	0	3.03	3.03	2.87	2.43
Pioneer	Trapper	12	0	0	0	0	3.44	3.44	3.44	3.44
Cajalco	Trautwein	12	0	0	0	0	2.29	2.29	1.84	1.56
Santa Rosa	Travis	12	0	0	0	0	0	0	0	0
Montecito	Tremaine	4.16	0	0	0	0	0.6	0	0	0
Bedford	Trenton	4.16	0	0	0	0	0.73	0	0	0
Railroad	Trestle	12	0	0	0	0	3.2	3.2	3.17	2.69
Eisenhower	Trevino	33	0	0	0	0	27	27	27	24.35
Gallatin	Trey	12	0.82	0.82	0.82	0.82	3.18	3.18	3.18	2.94
Alhambra	TriCity	16	0.4	0.4	0.4	0.4	8.63	6.39	5.77	5.35
Beverly	Triangle	4.16	0.45	0	0	0	0.94	0	0	0
Indian Wells	Tribal	12	0	0	0	0	0	0	0	0
State Street	Tribune	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Nogales	Trident	12	0	0	0	0	2.31	2.31	2.31	2.31
Isla Vista	Trigo	16	2.86	2.86	0	0	10.32	7.98	7.2	6.67
Broadway	Trimble	4.16	0	0	0	0	0.7	0	0	0
Ely	Trinidad	12	0.22	0.22	0.22	0.22	3.14	3.14	3.14	3.14
Alessandro	Trinity	12	0.75	0.75	0.75	0.75	3.34	3.34	3.34	2.9
Borrego	Tripas	12	0	0	0	0	3.18	3.18	3.18	3.18
Alhambra	Triumph	16	9.82	9.82	9.82	9.82	10.01	6.59	6.59	6.59
Malibu	Triunfo	16	7.51	3.97	3.97	3.97	8.08	7.19	5.94	5.49
Bullis	Trochu	16	3.44	3.44	3.44	3.44	6.55	5.4	4.93	4.52
Niguel	Trombone	12	0.35	0.35	0.35	0.35	3.41	3.41	3.41	3.11
Lancaster	Tropico	12	0	0	0	0	1.85	1.85	1.85	1.66
Ravendale	Trotter	16	3.97	0	0	0	6.93	0	0	0
Doheny	Trousdale	4.16	0	0	0	0	0.63	0	0	0

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Casa Diablo	Trout	33	0	0	0	0	0	0	0	0
Hoyt	Troy	4.16	0.35	0.35	0.35	0.35	1.28	0.78	0.62	0.52
Floraday	Trublu	4.16	0.09	0.09	0.09	0.09	0.81	0.37	0.37	0.31
Firehouse	Truck	12	2.64	2.64	2.64	2.64	3.41	3.41	3.41	3.41
Stirrup	Trudie	4.16	0.24	0	0	0	0.62	0	0	0
Valley	Trumble	12	2.61	2.61	2.61	2.61	3.02	3.02	2.35	1.99
Goleta	Trump	16	9.43	9.43	3.97	3.97	7.07	5.99	5.35	4.97
Elizabeth Lake	Trumpet	16	0	0	0	0	1.96	1.58	1.41	1.31
Bridge	Truss	4.16	0	0	0	0	1.08	0.98	0.55	0.47
Yorba Linda	Tsunami	12	1.66	1.66	1.66	1.66	3.03	3.03	3.03	2.77
Elizabeth Lake	Tuba	16	3.97	3.97	3.97	3.97	7.86	6.55	5.98	5.45
Vail	Tube	16	0.03	0.03	0.03	0.03	7.8	6.53	5.87	5.46
Bullis	Tucker	4.16	0.68	0.68	0.68	0.68	0.75	0.75	0.56	0.48
Mayberry	Tudor	12	2.61	2.61	2.07	2.07	2.96	2.96	2.96	2.8
Lundy	Tufa	16	0	0	0	0	0	0	0	0
Tulare	Tuggle	12	0	0	0	0	0	0	0	0
Placentia	Tuition	12	0	0	0	0	3.08	3.08	3.08	3.08
Lucas	Tulane	4.16	0	0	0	0	0.75	0	0	0
Barre	Tulip	12	1.31	1.31	1.31	1.31	3.31	3.31	3.31	3.18
Padua	Tully	12	0.61	0.61	0.61	0.61	2.84	2.84	2.52	2.14
Trask	Tulsa	12	1.69	1.69	1.69	1.69	3.01	3.01	3.01	3.01
Tumbleweed P.T.	Tumbleweed	2.4	0	0	0	0	0	0	0	0
Tapia	Tuna	16	1.06	1.06	1.06	1.06	5.29	4.44	4.01	3.72
Greening	Tundra	12	2.38	2.38	2.38	2.38	3.28	3.28	3.28	3.28
Isabella	Tungsten	12	0	0	0	0	0	0	0	0
Aqueduct	Tunnel	12	0.44	0.44	0.44	0.44	2.43	2.04	1.62	1.35
Peyton	Tupelo	12	0	0	0	0	3.33	3.33	3.33	3.33
Aqueduct	Turbine	12	1.7	1.7	1.7	1.7	3.17	3.17	2.74	2.32
Arcadia	Turf	4.16	0	0	0	0	0.68	0	0	0
Ordway	Turkey	12	0	0	0	0	0	0	0	0
Moreno	Turmeric	12	0	0	0	0	3.49	3.49	3.18	2.69
Walnut	Turnbull	12	4.09	3.02	3.02	3.02	2.64	2.64	2.64	2.64
Tulare	Turner	12	0	0	0	0	0	0	0	0
Aqueduct	Turnout	12	0	0	0	0	0.53	0.52	0.39	0.32
Santa Barbara	Turnpike	16	3.23	3.23	3.23	3.23	7.77	6.46	5.85	5.41
Bloomington	Turntable	12	0	0	0	0	3.45	3.45	3.45	3.07
Cabrillo	Turtle	12	0.54	0.54	0.54	0.54	1.88	1.88	1.68	1.42
Apple Valley	Tussing	12	2.99	2.99	2.99	2.99	2.08	1.61	1.28	1.09
Palmdale	Twain	12	0.28	0.28	0.28	0.28	3.32	3.32	2.82	2.39
Lynwood	Tweedy	4.16	0.52	0	0	0	0.78	0	0	0
Santa Monica	TwentySixSt	4.16	0.9	0	0	0	0.61	0	0	0
Venice Hill	TwinButte	12	0	0	0	0	0	0	0	0
Santa Susana	TwinLakes	16	0	0	0	0	4.68	3.91	3.55	3.28
Jersey	Twining	16	5.34	5.34	3.97	3.94	9.71	7.46	6.73	6.25
La Habra	Twister	12	1.99	1.99	1.99	1.99	3.41	3.41	3.41	3.41
Tyburn P.T.	Tyburn	4.16	0.49	0	0	0	0.82	0	0	0
Puente	Tyhard	12	0	0	0	0	3.49	3.49	3.49	3.49
Amador	Tyler	4.16	0	0	0	0	0.72	0	0	0
Yorba Linda	Typhoon	12	0	0	0	0	2.93	2.93	2.65	2.25
Porterville	Ulmer	4.16	0	0	0	0	0	0	0	0
Mt. Tom	Underwood	12	0	0	0	0	0	0	0	0
Styx P.T.	Underworld	12	3.02	3.02	3.02	3.02	1.06	0.89	0.66	0.55
San Bernardino	Unicorn	12	0.25	0.25	0.25	0.25	0	0	0	0
Santa Fe Springs	Union	12	0	0	0	0	3.49	3.49	3.49	3.49
Bandini	UnionPacific	16	2.17	2.17	2.17	2.17	8.68	7.08	6.32	5.84
Rivera	Unity	4.16	0.27	0	0	0	1.04	0.54	0.54	0.45
Bassett	Unruh	12	0	0	0	0	3.4	3.4	3.4	3.4
Cucamonga	Unser	12	1.04	1.04	1.04	1.04	3.25	3.25	3.25	3.25
Camden	Uranium	12	3.46	3	3	3	1.97	1.97	1.97	1.97
Homart	Urbita	12	0.84	0.84	0.84	0.84	3.06	3.06	2.63	2.23
Twentynine Palms	Utah	12	3.02	3.02	3.02	3.02	1.77	1.77	1.52	1.28
Goldhill	Ute	33	0	0	0	0	27	0	0	0
Nogales	Utopia	12	2.84	2.84	2.84	2.84	3.35	3.35	3.35	3.04
Borrego	Vaca	12	3.02	3.02	3.02	3.02	3.47	3.47	3.47	3.47
Shuttle	Vadar	12	4.02	3.02	3	3	2.55	2.55	2.15	1.81
Saugus	ValVerde	16	3.97	3.97	3.97	3.97	11.61	7.99	7.12	6.62
Delano	Valente	12	0	0	0	0	0	0	0	0
Nogales	Valiant	12	0	0	0	0	2.8	2.8	2.36	1.96
Puente	Valinda	12	0.84	0.84	0.84	0.84	3.48	3.48	3.48	3.43
Carpinteria	Vallecito	16	1.39	1.39	1.39	1.39	5.65	4.75	4.28	3.98
Valley Of The Moon P.T.	ValleyOfTheMoon	2.4	0.26	0	0	0	0.83	0	0	0
Palos Verdes	Valmonte	4.16	0.58	0	0	0	0.66	0	0	0
Anita	Valnett	4.16	0	0	0	0	1.02	0.52	0.52	0.44
Bassett	Valsun	12	1.04	1.04	1.04	1.04	3.41	3.41	3.41	3.02
Ditmar	Valve	16	3.77	0	0	0	6.67	0	0	0
Brookhurst	VanBrocklin	12	3.25	3.02	3.02	3.02	2.9	2.9	2.9	2.56
Atwood	VanBuren	12	0	0	0	0	3.16	3.16	3.16	3.16
Pico	VanCamp	12	3.02	3.02	0	0	3.49	3.49	3.49	3.49
Howard	VanWick	4.16	0	0	0	0	1.26	0.63	0.63	0.53
Amalia	Vancouver	4.16	0.1	0.1	0.1	0.1	1.28	0.85	0.66	0.56

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Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Porterville	Vandalia	12	0	0	0	0	0	0	0	0
Estero	Vanguard	16	3.97	3.97	3.97	3.97	9.29	7.35	6.68	6.15
Potrero	Vaquero	16	0	0	0	0	5.89	5.89	5.17	4.77
Lafayette	Vardon	12	4.4	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Shandin	Vargas	12	4.91	4.91	3.02	3.02	3.08	3.08	2.94	2.5
Shandin	Varsity	12	4.03	4.03	3.78	3.78	3.3	3.3	3.3	3.3
Cabrillo	Vasco	12	0.1	0	0	0	3.46	0	0	0
Solemint	Vasquez	16	1.34	1.34	1.34	1.34	6.14	5.12	4.67	4.28
Corona	Vassal	12	6.04	3.02	3.02	3.02	1.72	1.72	1.72	1.72
Cortez	Vecino	12	0.92	0.92	0.92	0.92	3.39	3.39	3.39	3.39
Moraga	Velardo	12	0	0	0	0	2.91	2.91	2.65	2.2
Eisenhower	Vella	33	20.36	20.36	20.36	20.36	27	27	27	27
Amador	Velma	16	3.97	3.97	3.97	3.97	8.49	7.21	6.41	5.95
Bluff Cove	Venus	4.16	0	0	0	0	0.73	0.73	0.48	0.41
Brea	VeraCruz	12	0	0	0	0	2.74	2.74	2.17	1.84
Barre	Verbena	12	2.27	2.27	2.27	2.27	3.4	3.4	3.4	3.4
Hedda	Verde	4.16	0.08	0.08	0.08	0.08	1.22	0.83	0.64	0.53
Calectric	Verdemont	33	8.38	8.38	8.38	8.38	20.95	13.03	9.15	6.84
Padua	Verdi	12	2.96	2.96	2.96	2.96	2.95	2.95	2.95	2.78
La Canada	Verdugo	16	3.97	3.97	3.97	3.97	5.16	4.82	3.97	3.64
Windsor Hills	Verdun	4.16	0.38	0	0	0	0.65	0	0	0
Carolina	Vermont	12	2.31	2.31	2.31	2.31	3.23	3.23	3.23	3.23
Amalia	Verona	4.16	0	0	0	0	0.76	0	0	0
San Fernando	Veterans	16	3.97	3.97	3.97	3.97	6.51	5.44	4.92	4.57
Moraga	ViaNorte	12	0	0	0	0	3.49	3.49	2.83	2.4
Stoddard	Viaduct	4.16	1.1	1.1	1.1	1.01	1.18	0.57	0.57	0.48
Cortez	Viaverde	12	0.6	0.6	0.6	0.6	2.98	2.98	2.38	2.02
Valdez	Vicasa	16	0	0	0	0	4.61	3.85	3.48	3.23
Corona	Vicentia	12	1.11	1.11	1.11	1.11	2.39	2.39	2.39	2.39
Passons	Vicki	12	0	0	0	0	2.11	2.11	2.11	1.85
Eaton	Video	16	5.95	3.97	3.97	3.97	7.15	6.33	5.03	5.03
Monolith	Viento	12	0	0	0	0	1.12	0.75	0.61	0.51
Lakewood	Viking	4.16	0	0	0	0	0.93	0.56	0.4	0.34
Perry	Villa	4.16	0.04	0.04	0.04	0.04	1.27	0.6	0.6	0.5
Euclid	Village	4.16	0	0	0	0	1.28	0.64	0.64	0.53
Farrell	Viminal	12	0.7	0.7	0.7	0.7	2.87	2.87	2.87	2.49
Moraga	Vine	12	3.78	3.78	3.78	3.02	3.16	3.16	3.16	2.68
Saticoy	Vineyard	16	0	0	0	0	4.98	4.15	3.74	3.46
Rolling Hills	Violet	4.16	0.91	0.91	0.91	0.91	1.25	0.89	0.59	0.5
Niguel	Violin	12	0.25	0.25	0.25	0.25	2.27	2.27	2.27	2.27
Gisler	Viper	12	2.98	2.98	2.98	0	2.8	2.8	2.8	2.73
Chatham	Virgil	12	0	0	0	0	0	0	0	0
Estrella	Virgo	12	0	0	0	0	0	0	0	0
Industry	Vise	12	0	0	0	0	3.42	3.42	3.42	3.42
Brewster	Vita	4.16	0.07	0	0	0	0.79	0	0	0
Timoteo	Vitamin	12	1.07	1.07	1.07	1.07	3.04	3.04	3.04	2.67
Vogan P.T.	Vogan	4.16	0.77	0	0	0	1.27	0	0	0
Liberty	Volney	12	0	0	0	0	0	0	0	0
Farrell	Volturno	12	1.17	1.17	1.17	1.17	3.02	3.02	3.02	2.64
Dalton	Von	12	3.86	3.02	3.02	3.02	3.49	3.49	3.43	2.78
Yorba Linda	Vortex	12	3.05	3.05	3.02	3.02	3.29	3.29	3	2.52
Woodville	Vossler	12	0	0	0	0	0	0	0	0
Gisler	Voyager	12	2.99	0	0	0	3.49	0	0	0
Casa Diablo	Vulcan	33	0	0	0	0	0	0	0	0
Imperial	Vultair	12	2.47	2.47	2.47	2.47	2.12	2.12	2.12	2.12
Lennox	Vultee	16	4.94	3.97	3.97	3.97	7.79	6.66	5.9	5.45
Trask	Waco	12	4.15	3.02	3.02	3.02	3.37	3.37	3.37	3.34
Ocean Park	Wadsworth	4.16	0	0	0	0	0.71	0	0	0
Howard	Wagner	4.16	0	0	0	0	1.27	0.62	0.49	0.41
Randall	Wahlstrom	12	0.33	0.33	0.33	0.33	3.42	3.42	3.42	3.31
Nogales	Wahoo	12	0	0	0	0	3.34	3.34	3.34	2.95
MacArthur	Wainwright	12	0.28	0.28	0.28	0.28	3.29	3.29	3.29	3.29
Skylark	Waite	12	0.7	0.7	0.7	0.7	3.12	3.05	2.4	2.02
Marine	Walgrove	16	3.97	3.97	3.97	3.97	9.22	7.56	6.81	6.33
Delano	Wallace	12	0	0	0	0	0	0	0	0
Huntington Park	WalnutPark	4.16	0.15	0.15	0.15	0.15	1.24	0.93	0.66	0.56
Signal Hill	Walrus	12	3.88	3.88	3.88	3.78	3.49	3.49	3.49	3.49
Stewart	Walter	12	0	0	0	0	3.41	3.41	3.41	3.31
Sunnyside	Wanda	12	0	0	0	0	2.47	2.47	2.36	1.98
Fair Oaks	Wapello	4.16	0.2	0.2	0.2	0.2	1.08	0.68	0.53	0.45
Longdon	Ward	4.16	0.7	0.7	0.7	0.7	1.26	0.81	0.65	0.54
Newcomb	Wardell	12	0	0	0	0	3.08	3.08	2.59	2.12
Los Cerritos	Wardlow	4.16	0.05	0.05	0.05	0.05	1.15	0.78	0.6	0.51
Kimball	Warhawk	12	3.61	3.02	3.02	3.02	3.21	3.21	2.71	2.3
Cardiff	WarmCreek	12	0.3	0.3	0.3	0.3	0	0	0	0
Randolph	Warman	16	7.93	0	0	0	7.32	0	0	0
Bedford	Warner	4.16	0	0	0	0	0.61	0	0	0
Team	Warriors	12	1.45	1.45	1.45	1.45	3.37	3.37	3.37	3.37
Sangar	Warwick	4.16	0	0	0	0	0.74	0.49	0.39	0.33
Rio Hondo	Wash	16	0	0	0	0	9.31	5.99	5.37	4.99

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Vegas	Wasp	16	0.43	0.43	0.43	0.43	8.73	7.23	6.52	6.06
Brookhurst	Waterfield	12	0	0	0	0	3.16	3.16	3.16	2.83
Cardiff	Waterman	12	3.02	3.02	3.02	3.02	3.48	3.48	3.48	3.29
North Intake	Waterwheel	12	1.11	1.11	1.11	1.11	3.49	3.49	2.65	2.07
Graham	Watts	4.16	0.99	0	0	0	0.65	0	0	0
Bovine	Watusi	12	2.27	2.27	2.27	2.27	3.41	3.41	3.41	3.15
Fremont	Wayside	16	5.88	5.88	3.97	3.97	9.44	7.73	6.97	6.46
Basta	Wealth	4.16	0.39	0.39	0.39	0.39	1.24	0.59	0.59	0.5
Hoyt	Weaver	4.16	0.27	0.27	0.27	0.27	1.25	0.54	0.54	0.45
Oak Grove	Webb	12	0	0	0	0	0	0	0	0
South Gate	Webbwood	4.16	0	0	0	0	0.6	0	0	0
Ganesha	Weber	4.16	0.44	0.44	0.44	0.44	0.92	0.56	0.44	0.37
State Street	Webster	12	1.32	1.32	1.32	1.32	2.68	2.68	2.68	2.68
Defrain	Wedge	12	3.46	2.07	2.07	2.07	3.44	3.44	3.42	2.72
Narod	Weeks	12	1.31	1.31	1.31	1.31	3	3	3	3
Weesha P.T.	Weesha	2.4	0	0	0	0	1.29	0	0	0
Canyon	Weir	12	1.91	0	0	0	3.41	0	0	0
Chase	Weirick	12	0.93	0.93	0.93	0.93	3.43	3.43	3.33	2.83
Alon	Weiser	12	3.73	3.73	3.73	3.02	0	0	0	0
Lafayette	Weiskoff	12	1.45	0	0	0	3.46	0	0	0
Bryman	Weiss	4.16	0.26	0.26	0.26	0.26	0.84	0.52	0.41	0.34
Vestal	Welch	12	0	0	0	0	0	0	0	0
Palm Village	Welcome	4.8	0	0	0	0	0	0	0	0
Venida	Wells	12	0	0	0	0	0	0	0	0
Covina	Werden	4.16	0	0	0	0	1.13	0.7	0.56	0.47
Culver	Wesley	4.16	0	0	0	0	0.55	0	0	0
Delano	WestCity	4.16	0	0	0	0	0	0	0	0
Maxwell	Westbluff	12	0	0	0	0	3.1	2.6	2.06	1.74
Murrietta	Westbrook	12	3.4	3.02	3.02	3.02	2.94	2.94	2.94	2.6
Westend P.T.	Westend	12	0	0	0	0	0	0	0	0
Yukon	Western	16	5.52	0	0	0	7.06	0	0	0
Westfall P.T.	Westfall	4.16	0.55	0	0	0	0.64	0	0	0
Bassett	Westfield	12	0.81	0.81	0.81	0.81	2.87	2.87	2.72	2.3
Westmont P.T.	Westmont	4.16	0.62	0	0	0	1.27	0	0	0
Earlimart	Weston	12	0	0	0	0	0	0	0	0
Olympic	Wetherly	4.16	0.03	0	0	0	0.62	0	0	0
El Nido	Whale	16	3.12	3.12	3.12	3.12	8.54	6.98	6.28	5.83
Tulare	Whey	12	0	0	0	0	0	0	0	0
Quartz Hill	Whip	12	2.14	2.14	2.14	2.14	2.46	2.46	2.46	2.05
Olinda	Whipstock	12	3.02	3.02	3.02	3.02	3.06	3.06	3.06	2.6
Chiquita	Whiskey	12	0.79	0.79	0.79	0.79	3.09	3.09	3.09	3.09
Chase	Whisper	12	0	0	0	0	3.44	3.41	3.41	2.83
La Palma	Whitaker	12	4.34	4.34	3.46	3.02	3.44	3.44	3.44	3.44
Longdon	White	4.16	0.9	0	0	0	0.7	0	0	0
Thousand Oaks	Whitecliff	16	0	0	0	0	5.81	4.81	4.29	3.99
Joshua Tree	Whitehorn	12	2.33	2.33	2.33	2.33	3.18	3.18	2.83	2.38
Milliken	Whitehorse	12	1.38	1.38	1.38	1.38	3.16	3.16	3.16	2.73
Oak Grove	Whitendale	12	0	0	0	0	0	0	0	0
Wabash	Whiteside	16	3.94	3.94	3.94	3.94	9.42	7.88	7.08	6.58
Sepulveda	Whiting	16	7.7	3.97	3.97	3.97	10.5	8.04	7.24	6.63
Tippecanoe	Whitlock	4.16	1.01	0	0	0	0.91	0	0	0
Rosemead	Whitmore	16	0	0	0	0	8.79	7.45	6.71	6.16
Calden	Whitsett	16	2.51	2.51	2.51	2.51	8.66	7.32	6.52	6.06
Declez	Whittram	4.16	1.01	1.01	1.01	1.01	1.26	0.7	0.51	0.43
Friendly Hills	Whittwood	4.16	0	0	0	0	1.18	0.82	0.63	0.5
Beverly	Whitworth	16	1.32	1.32	1.32	1.32	8.06	8.06	7.09	6.59
Malibu	Whizzin	16	6.59	6.59	3.97	3.97	8.81	7.59	6.74	6.14
Trask	Wichita	12	3.02	3.02	3.02	3.02	3.29	3.29	3.29	3.29
Camarillo	Wigton	16	5.29	4.96	3.94	3.94	11.68	6.96	6.29	5.81
Bloomington	Wigwag	12	0.43	0.43	0.43	0.43	3.18	3.18	2.89	2.34
Laurel	Wilbur	12	0	0	0	0	0	0	0	0
Cudahy	Wilcox	16	4.22	4.22	4.22	3.94	7.57	6.29	5.62	5.18
Bullis	Wildcat	16	7.29	7.29	3.97	3.97	7.39	6.16	5.51	5.12
Mariposa	Wildflower	12	0	0	0	0	0	0	0	0
Elsinore	Wildomar	33	9.58	9.58	9.58	9.58	27	16.28	9.99	7.83
Newhall	Wildwood	16	0.06	0.06	0.06	0.06	6.83	5.23	5.23	4.79
Newhall	Wiley	16	2.58	2.58	2.58	2.58	7.52	6.01	5.4	5.01
Ravendale	Willard	16	0	0	0	0	10.18	6.46	5.8	5.39
Sullivan	Willets	12	2.93	2.93	2.93	2.93	2.97	2.97	2.97	2.97
Stewart	William	12	0	0	0	0	3.43	3.43	3.43	3.43
Upland	Willis	12	0.15	0.15	0.15	0.15	3.25	3.25	3.25	3.25
Watson	Willow	12	5.62	5.62	5.62	3	3.49	3.49	3.49	3.49
Rosamond	WillowSprings	12	3.02	3.02	3.02	3.02	3.29	2.44	1.94	1.64
Ramona	Wilmar	4.16	0	0	0	0	0.69	0	0	0
Alon	Wilmington	12	4.21	0	0	0	3.44	3.44	3.44	3.44
Beverly	Wilshire	4.16	1.01	0	0	0	0.66	0	0	0
Yucaipa	WilsonCreek	12	3.58	3.58	3.02	3.02	2.67	2.67	2.23	1.9
Dalton	Winark	12	2.42	2.42	2.42	2.42	2.97	2.97	2.97	2.97
Alder	WindTunnel	12	1.92	1.92	1.92	1.92	3.36	3.36	3.36	3.12
Pico	Windham	12	6.31	3.02	3.02	3.02	3.49	3.49	3.49	3.49

Substation	Distribution Circuit	Voltage (kV)	Consuming DER Hosting Capacity Line Section 1 (MW)	Consuming DER Hosting Capacity Line Section 2 (MW)	Consuming DER Hosting Capacity Line Section 3 (MW)	Consuming DER Hosting Capacity Line Section 4 (MW)	Producing DER Hosting Capacity Line Section 1 (MW)	Producing DER Hosting Capacity Line Section 2 (MW)	Producing DER Hosting Capacity Line Section 3 (MW)	Producing DER Hosting Capacity Line Section 4 (MW)
Winding P.T.	Winding	4.16	0.3	0	0	0	1.29	0	0	0
Channel Island	Windjammer	16	2.29	2.29	2.29	2.29	6.9	5.83	5.25	4.86
Laurel	Windt	12	0	0	0	0	0	0	0	0
Pauba	Winery	12	3.02	3.02	3.02	3.02	2.36	1.77	1.43	1.19
Pedley	Wineville	12	0	0	0	0	2.56	2.56	2.56	2.41
Gonzales	Winford	16	0	0	0	0	6.99	6	5.33	4.91
Savage	Wing	12	1.78	1.78	1.78	1.78	3.24	3.24	3.09	2.62
MacArthur	Wingate	12	0	0	0	0	3.49	3.49	3.49	3.27
Chestnut	Wingnut	12	3.02	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Rolling Hills	Winlock	16	5.52	0	0	0	7.17	0	0	0
West Riverside	Winnebago	12	2.11	2.11	2.11	2.11	3.33	3.33	3.33	3.24
Trophy	Winner	12	3.52	3.52	3.02	3.02	3.49	3.49	3.49	3.49
Bullis	Winona	16	3.09	3.09	3.09	3.09	8.56	6.9	6.21	5.75
Belding	Winterhaven	4.16	0	0	0	0	0.88	0.75	0.48	0.41
Dunes	Winters	12	5.45	3.02	3.02	3	1.34	0.94	0.75	0.63
Oceanview	Wintersburg	12	1.28	1.28	1.28	1.28	3.18	3.18	3.18	3.16
Live Oak	Winthrop	12	1.79	1.79	1.79	1.79	2.9	2.9	2.9	2.61
Carolina	Wisconsin	12	1.05	1.05	1.05	1.05	3.21	3.21	3.21	3.21
Davidson City	Wise	4.16	0.17	0.17	0.17	0.17	1.21	0.78	0.52	0.43
Anita	Wistaria	4.16	0	0	0	0	0.63	0	0	0
Lucas	Wolf	12	0	0	0	0	3.34	3.34	3.34	3.08
Cathedral City	WonderPalms	4.8	0	0	0	0	0.42	0.28	0.21	0.17
Oak Park	Woodhaven	16	3.97	3.97	3.97	3.97	8.65	7.14	6.64	5.99
Liberty	Woodland	12	0	0	0	0	0	0	0	0
Colonia	Woodroad	16	7.58	7.58	7.58	7.58	13.2	6.36	6.36	6.36
Belmont	Woodrow	4.16	0.63	0	0	0	0.69	0	0	0
Badillo	Woodside	4.16	0.02	0	0	0	0.71	0	0	0
Peyton	Woodview	12	1.17	1.17	1.17	1.17	3.34	3.34	3.34	3.34
Alhambra	Woodward	4.16	0.72	0.72	0	0	0.98	0.98	0.7	0.58
Shuttle	Wookie	12	0	0	0	0	1.89	1.89	1.84	1.55
Michillinda	Woolley	4.16	0	0	0	0	1.06	0.69	0.55	0.46
Porterville	Worth	12	0	0	0	0	0	0	0	0
Rector	Wutchumna	12	0	0	0	0	0	0	0	0
Chase	Wyle	12	0	0	0	0	2.95	2.66	2.06	1.74
Carolina	Wyoming	12	0	0	0	0	3.19	3.19	3.19	2.88
Cabrillo	Xerox	12	3.49	3.02	3.02	3.02	3.49	3.49	3.49	3.49
Hathaway	Ximeno	12	1.74	0	0	0	3.49	0	0	0
Johanna	Yahtzee	12	3.46	3.02	3	3	3.49	3.49	3.49	3.49
Colorado	Yale	4.16	1.01	0	0	0	0.69	0	0	0
Cucamonga	Yarborough	12	0	0	0	0	2.64	2.64	2.64	2.26
Vail	Yates	16	4.43	3.97	3.97	3.97	5.77	4.82	4.37	4.04
Orange	Yellow	12	3.02	3.02	3.02	3.02	3.42	3.42	3.42	3.42
Riverway	Yellowstone	12	0	0	0	0	0	0	0	0
Bayside	Yellowtail	12	0	0	0	0	3	3	2.92	2.44
Santiago	Yen	12	0	0	0	0	3.44	3.44	3.44	3.37
Newmark	Ynez	4.16	0	0	0	0	1.22	0.71	0.56	0.47
Shuttle	Yoda	12	4.9	4.9	3	3	3.17	3.17	3.17	3.17
Hamilton	Yogi	12	2.61	2.61	2.61	2.61	2.72	2.72	2.72	2.68
Perez	Yorba	4.16	0.36	0.36	0.36	0.36	1.26	0.84	0.67	0.56
Yukon	York	4.16	0.34	0.34	0.34	0.34	1.28	0.86	0.6	0.51
Narrows	Yorktown	12	1.94	1.94	1.94	1.94	3.39	3.39	3.39	3.16
Santa Susana	Yosemite	16	1.64	1.64	1.64	1.64	5.64	4.72	4.26	3.93
Beverly	Young	16	3.6	3.6	3.6	3.6	7.56	7.56	6.48	6
Brookhurst	Younger	12	0.65	0.65	0.65	0.65	3.43	3.43	3.43	3.03
Chino	Younkin	12	2.35	2.35	2.35	2.35	3.42	3.42	3.42	3.42
Coffee	Yuban	12	0.6	0.6	0.6	0.6	3.29	3.29	3.29	3.29
Brea	Yucatan	12	0	0	0	0	3.33	3.33	3.33	3.27
Lancaster	Yucca	4.16	1.01	0	0	0	0.79	0	0	0
Rancho	YuccaLoma	12	3.02	3.02	3.02	3.02	2.81	2.81	2.75	2.33
Sullivan	Yuma	12	0	0	0	0	3.48	3.48	3.48	3.48
Fremont	Zamora	16	0	0	0	0	9.23	7.79	6.99	6.5
Sunnyside	Zane	12	0.63	0.63	0.63	0.63	2.97	2.97	2.97	2.55
Maxwell	Zantar	12	1.18	0	0	0	3.36	3.36	3.36	3.36
Strathmore	Zante	12	0	0	0	0	0	0	0	0
Cardiff	Zapata	12	0.01	0.01	0.01	0.01	0	0	0	0
Quartz Hill	Zappa	12	1.99	1.99	1.99	1.99	2.97	2.97	2.97	2.97
Victor	Zasadni	12	0.36	0.36	0.36	0.36	2.61	2.61	2.61	2.32
El Nido	Zebra	16	3.97	3.97	3.97	3.97	8.26	6.36	5.71	5.31
Bovine	Zebu	12	2.84	2.84	2.84	2.84	2.73	2.73	2.43	2.04
Loraine	Zenda	12	3.02	3.02	3.02	3.02	3.44	3.44	3.44	3.06
Carson	Zeno	16	6.14	6.14	3.97	3.97	10.72	7.63	6.88	6.39
Walteria	Zepher	16	7.19	3.97	3.97	3.94	8.2	6.79	6.26	5.69
Nola	Zeppelin	16	9.25	3.97	3.97	3.97	8.44	7.1	6.29	5.85
Proctor	Zeus	12	1.04	0	0	0	3.46	0	0	0
Murrietta	Zevo	12	1.57	1.57	1.57	1.57	3.49	3.49	3.34	2.78
Randall	Zimmer	12	0	0	0	0	3.18	3.18	3.18	3.18
Crest	Zinc	16	3.97	3.94	3.94	3.94	7.23	6.23	5.38	4.93
Pepper	Zinfandel	12	0.63	0.63	0.63	0.63	2.11	2.11	2.04	1.72
Archline	Zinser	12	0.12	0.12	0.12	0.12	3.35	3.35	3.35	3.32
Terra Bella	Zion	12	0	0	0	0	0	0	0	0

			Consuming DER Hosting Capacity				Producing DER Hosting Capacity			
Substation	Distribution Circuit	Voltage (kV)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)	Line Section 1 (MW)	Line Section 2 (MW)	Line Section 3 (MW)	Line Section 4 (MW)
Stetson	Zippy	12	1.18	1.18	1.18	1.18	3.48	3.48	3.48	3.3
Crest	Zircon	16	5.09	5.09	3.97	3.97	9.36	7.75	6.86	6.31
Estrella	Zodiac	12	0	0	0	0	3.49	3.49	3.49	3.49
Randolph	Zoe	16	1.93	1.93	1.93	1.93	10.37	8.84	6.73	6.23
Moorpark	Zone	16	3.97	3.94	3.94	3.94	6.18	5.19	4.67	4.34
Victor	Zuni	33	0	0	0	0	27	27	23.37	16.37

Appendix J: DER Growth Scenarios Worksheets

As part of the DRP, SCE developed three 10-year scenarios that project expected growth of DERs through 2025. The DER Growth Scenarios Worksheets show the substation name, circuit name, voltage for the distribution circuit, and the aggregated capacity forecasts for each scenario. These forecasts are aggregated by assuming that generating DERs (e.g., solar PV) are positive values, while consuming DERs (e.g., plug-in electric vehicles) are negative values. The aggregated forecasts include the total DER capacity and the coincident capacity, which shows the amount of DERs available at the distribution circuit peak time.

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Highland	Abacus	12.0	0.57	0.97	0.81	4.81	1.48	6.64
Greening	Abana	12.0	0.65	0.81	1.03	5.51	1.13	5.94
Bliss	Abbey	12.0	0.27	0.43	0.37	2.40	0.53	3.26
Ellis	Abbot	12.0	1.00	1.85	1.48	10.31	1.92	12.11
Bovine	Aberdeen	12.0	0.26	0.24	0.36	1.62	0.62	2.07
Cortez	Abigail	12.0	0.75	0.92	1.09	5.12	1.66	6.37
Cudahy	Able	4.16	0.15	0.22	0.22	1.40	0.25	1.62
Neptune	Abri	12.0	0.39	0.49	0.60	2.73	0.80	3.05
Milliken	Absolut	12.0	0.62	0.85	1.00	5.75	1.09	6.19
Newbury	Academy	16.0	0.65	1.73	0.91	9.54	1.09	11.90
Mayberry	Acadian	12.0	0.19	0.53	0.28	2.72	0.34	3.81
Pixley	Acala	12.0	0.53	0.75	0.75	4.06	1.15	5.44
Brea	Acapulco	12.0	0.04	0.36	0.05	1.04	0.08	2.00
Moreno	Accent	12.0	0.29	0.66	0.38	3.24	0.69	4.91
Timberwine	Access	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Goleta	Ace	16.0	0.21	0.28	0.19	1.85	0.35	2.46
Newmark	Ackley	4.16	0.04	-0.06	0.02	0.56	0.10	0.79
Sullivan	Acme	12.0	0.44	0.60	0.70	3.59	0.85	3.82
Arcadia	Acorn	4.16	0.15	0.18	0.19	0.78	0.52	1.32
Randall	Acosta	12.0	0.48	0.80	0.60	3.87	1.27	6.17
Morro	Acres	12.0	0.06	0.26	-0.11	2.59	-0.05	4.37
Anaverde	Acrobat	12.0	0.63	0.99	0.93	5.48	1.20	6.71
Bullis	Ada	4.16	0.14	0.26	0.20	1.49	0.25	1.75
Sunnyside	Adair	4.16	0.10	0.16	0.13	0.95	0.16	1.22
Yukon	Adak	16.0	0.21	0.45	0.33	2.75	0.36	3.00
Victoria	Addis	16.0	0.49	0.99	0.61	6.13	0.82	7.12
Victor	Adelanto	12.0	0.57	0.64	0.86	4.15	1.16	4.92
Chase	Adell	12.0	0.34	0.65	0.49	3.66	0.69	4.57
Pico	Admiral	12.0	1.23	1.72	1.97	11.20	2.06	13.16
Newmark	Adobe	16.0	0.06	0.09	0.01	1.18	0.06	1.58
Camarillo	Adolfo	16.0	0.84	0.98	1.31	6.65	1.57	7.36
Larder	Adriatic	4.16	0.17	0.31	0.23	1.90	0.29	2.25
Cherry	Afton	12.0	0.02	0.05	0.03	0.31	0.04	0.35
Wimbledon	Agassi	12.0	0.56	0.70	0.82	3.90	1.41	5.16
Morro	Agate	12.0	0.52	1.26	0.53	7.92	0.77	10.50
Tamarisk	Agave	12.0	0.81	1.04	1.24	5.74	1.77	7.05
Gisler	Agena	12.0	0.70	0.83	1.02	4.70	1.46	5.62
Bullis	Agnes	4.16	0.10	0.20	0.15	1.15	0.17	1.39
Laguna Bell	Agra	16.0	0.38	0.47	0.56	2.07	0.92	2.48
Hemet	Aguanga	12.0	0.18	0.28	0.26	1.80	0.36	2.13
Aha P.T.	Aha	12.0	0.11	0.13	0.16	0.72	0.24	0.85
Pico	Ahoy	12.0	0.15	0.20	0.24	1.30	0.26	1.53
Cajalco	Aidan	12.0	0.34	1.03	0.46	3.20	1.05	6.15
Marine	Aircraft	16.0	0.06	0.07	0.09	0.38	0.11	0.40
Lancaster	Airport	12.0	0.76	1.04	1.05	4.14	2.10	6.02
Borrego	Ajard	12.0	0.12	0.34	0.12	2.84	0.13	3.44
Moulton	Akita	12.0	0.42	0.79	0.59	4.57	0.81	5.36
Trask	Akron	12.0	0.98	1.17	1.49	6.85	2.04	7.79
Redlands	Alabama	12.0	0.98	1.30	1.43	5.86	2.61	7.85
Modoc	Alamar	4.16	0.03	0.37	0.00	0.87	0.04	2.20
Imperial	Alameda	12.0	0.63	0.77	0.96	4.61	1.34	5.27
Seabright	Alamo	12.0	0.36	0.71	0.55	3.88	0.67	4.25
Live Oak	Alamosa	12.0	0.68	1.03	0.95	5.05	1.68	6.49
Yukon	Alaska	16.0	1.43	1.78	2.18	10.22	2.99	11.63
El Nido	Albacore	16.0	1.24	1.53	1.78	6.64	2.98	8.01
Randolph	Albany	16.0	0.61	0.80	0.93	4.30	1.20	5.07
Santa Monica	Albatross	16.0	0.54	1.11	0.70	6.38	0.93	7.38
Brewster	Alberta	4.16	0.09	0.12	0.13	0.98	0.17	1.14
Passons	Alburtis	12.0	0.38	0.75	0.54	4.39	0.77	5.74
Albury P.T.	Albury	4.16	0.04	0.03	0.05	0.28	0.12	0.38
Moraga	Alcalde	12.0	0.30	0.55	0.40	2.29	0.81	3.50
Randolph	Alcoa	16.0	0.92	1.18	1.41	6.37	1.85	7.46
Beverly	Alden	4.16	0.21	0.29	0.29	1.24	0.60	1.90
Palm Springs	Alejo	4.16	0.16	0.23	0.23	1.01	0.37	1.32

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Arro	Alexander	4.16	0.11	0.17	0.16	0.93	0.27	1.21
Redman	Alfalfa	12.0	0.05	0.07	0.07	0.45	0.10	0.58
San Miguel	Alfredo	16.0	1.42	1.73	2.11	8.20	3.12	9.35
Peyton	Alicia	12.0	0.52	1.15	0.75	5.95	1.11	7.93
Culver	Alla	16.0	0.33	0.62	0.48	3.73	0.57	3.98
Liberty	Allegiance	12.0	0.87	1.30	1.15	4.84	2.65	7.05
Carodean	Allegra	12.0	0.27	0.49	0.40	2.40	0.57	3.33
Cabrillo	Allergan	12.0	0.41	1.08	0.65	6.22	0.71	6.49
Cortez	Allison	12.0	0.84	1.04	1.30	5.76	1.65	6.36
Camden	Alloy	12.0	0.22	0.47	0.30	2.45	0.40	2.80
Lakewood	Allred	4.16	0.07	0.17	0.06	1.21	0.10	1.80
Homart	Allstate	12.0	0.51	1.02	0.78	5.45	0.94	5.84
Allview P.T.	Allview	2.4	0.02	0.05	0.03	0.26	0.03	0.31
Woodruff	Alma	4.16	0.13	0.12	0.17	1.19	0.27	1.42
Alhambra	Almansor	16.0	0.79	1.45	1.18	8.27	1.52	9.32
Chestnut	Almond	12.0	0.59	1.02	0.87	5.79	1.19	6.76
Alola	Alola	2.4	0.00	0.00	0.00	0.00	0.00	0.00
Woodruff	Alondra	4.16	0.19	0.25	0.26	1.26	0.49	1.73
Eric	Alora	12.0	0.49	0.64	0.72	3.64	1.13	4.49
Hoyt	Alpaca	4.16	0.11	0.17	0.16	1.02	0.18	1.22
Telegraph	Alpha	12.0	0.83	1.23	1.19	5.92	1.96	7.31
Alpine P.T.	Alpine	2.4	0.04	0.11	0.07	0.58	0.08	0.68
Mayflower	Alster	4.16	0.07	0.07	0.08	0.54	0.23	0.93
Archline	Alstot	12.0	0.28	0.41	0.38	2.39	0.75	3.36
Monrovia	Alta	4.16	0.10	0.20	0.14	1.09	0.22	1.48
Soquel	Alterra	12.0	0.72	1.34	1.12	9.19	1.35	10.92
Michillinda	Altura	4.16	0.02	0.11	0.01	0.59	0.02	1.01
Camden	Aluminum	12.0	0.43	0.99	0.62	5.87	0.72	6.61
Gonzales	Alvarado	16.0	0.74	1.25	1.05	6.92	1.29	8.12
Farrell	Alvera	12.0	0.71	1.08	1.05	5.17	1.74	7.11
Farrell	Amado	12.0	0.64	0.85	0.91	3.71	1.86	5.48
Gonzales	Amanda	16.0	0.38	0.72	0.54	4.02	0.68	4.63
Merced	Amar	12.0	0.54	0.68	0.79	5.82	0.92	6.39
Rio Hondo	Amazon	12.0	1.02	1.24	1.55	7.36	2.21	8.11
Tamarisk	Amber	12.0	0.45	0.58	0.65	2.66	1.15	3.61
Oak Park	Ambercrest	16.0	1.02	1.03	1.32	4.87	3.30	7.82
Marymount	Ambersky	16.0	0.50	1.09	0.70	6.35	0.76	7.68
Bradbury	Ambrus	16.0	0.55	0.75	0.77	5.18	1.22	6.39
Diamond Bar	Ambushers	12.0	0.50	0.56	0.63	2.69	1.72	4.38
Riverway	American	12.0	0.49	0.79	0.74	4.15	0.93	5.16
Moneta	Amestoy	4.16	0.10	0.15	0.15	1.03	0.17	1.15
Archline	Amethyst	12.0	0.46	0.78	0.61	3.51	1.43	5.62
Friendly Hills	Amigo	4.16	0.08	0.05	0.10	0.60	0.25	0.83
Bunker	Ammo	12.0	0.26	0.52	0.34	3.99	0.41	5.05
Somerset	Amos	4.16	0.09	0.08	0.12	1.05	0.12	1.09
Railroad	Amtrak	12.0	0.23	0.31	0.37	2.17	0.41	3.59
Covina	Amy	4.16	0.05	0.12	0.07	0.51	0.13	0.81
Santa Barbara	Anacapa	4.16	0.02	0.03	0.03	0.12	0.05	0.15
North Oaks	Anaconda	16.0	0.20	0.30	0.21	2.23	0.43	3.03
Edinger	Anahurst	4.16	0.18	0.65	0.27	2.32	0.28	3.92
Shuttle	Anakin	12.0	0.63	0.97	0.88	5.12	1.49	7.28
Modoc	Anapamu	4.16	0.11	0.40	0.15	1.01	0.26	1.94
San Antonio	Anawalt	12.0	0.45	0.80	0.63	4.24	0.93	5.18
Neptune	Anchor	4.16	0.05	0.08	0.06	0.66	0.07	0.79
Yukon	Anchorage	16.0	0.01	0.04	0.02	0.23	0.02	0.25
Glen Avon	Anderson	12.0	0.51	0.78	0.71	4.06	1.37	5.54
Mira Loma	Andes	12.0	1.42	1.73	2.18	9.44	2.64	10.16
Cucamonga	Andretti	12.0	0.65	0.85	1.00	5.04	1.31	5.92
Padua	Andria	12.0	0.49	0.74	0.64	3.80	1.48	5.97
Naomi	Andrus	4.16	0.14	0.23	0.20	1.25	0.25	1.44
Gould	Angeles	16.0	0.05	0.37	0.00	1.70	0.07	3.27
Victoria	Angelina	16.0	0.92	1.51	1.32	8.50	1.64	9.50
Fillmore	Angus	16.0	0.49	0.88	0.67	5.16	0.88	6.15
Merced	Ann	12.0	0.38	0.70	0.49	4.24	0.85	5.97
Santa Rosa	Annenberg	12.0	0.45	0.56	0.68	2.92	0.98	3.40
Marion	Annette	12.0	0.35	0.52	0.43	3.38	0.86	4.81
Lafayette	Annika	12.0	0.94	1.28	1.40	6.59	2.13	8.20
Borrego	Ante	12.0	0.23	0.59	0.27	4.10	0.34	5.36
Cabrillo	Anteater	12.0	0.45	0.95	0.71	5.60	0.78	5.95

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Stoddard	Antil	4.16	0.07	0.13	0.10	0.67	0.12	0.79
Timoteo	Antique	12.0	0.33	0.66	0.49	3.49	0.63	3.77
Nogales	Antler	12.0	0.64	0.72	0.92	4.89	1.36	6.05
Moorpark	Anton	16.0	0.31	0.88	0.44	3.67	0.59	5.49
Sullivan	Antone	12.0	0.58	0.78	0.91	4.41	1.12	4.72
Athens	Antwerp	4.16	0.11	0.14	0.17	0.95	0.17	1.05
Lennox	Anza	4.16	0.09	0.15	0.13	0.89	0.15	0.98
Athens	Anzac	4.16	0.12	0.17	0.19	1.16	0.19	1.28
Corona	Anzar	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Shawnee	Apache	12.0	0.53	0.64	0.79	3.30	1.22	4.03
Santa Rosa	Apartment	12.0	0.53	0.83	0.74	3.31	1.47	5.11
Laguna Bell	Apex	16.0	0.41	0.52	0.66	3.63	0.75	3.74
Auld	Appalousa	12.0	0.18	0.52	0.20	3.00	0.29	4.48
Naples	Appian	4.16	0.03	0.19	0.03	1.12	0.05	1.74
Citrus	Apple	12.0	0.80	0.88	1.10	4.77	2.30	6.81
Royal	Appleton	16.0	1.35	1.72	1.95	9.32	3.04	12.08
Fernwood	Apricot	16.0	0.40	0.52	0.63	3.00	0.74	3.29
Estrella	Aquarius	12.0	0.64	1.09	1.01	8.79	1.08	10.48
Modena	Arabia	12.0	0.34	0.68	0.33	4.03	0.90	6.83
Gavilan (115)	Arapaho	12.0	0.12	0.27	0.18	1.62	0.20	1.99
Mesa	Arboles	16.0	0.92	1.79	1.31	10.47	1.75	12.52
Arcadia	Arboretum	16.0	0.42	0.62	0.52	2.93	1.33	4.86
Inglewood	Arborvitae	4.16	0.26	0.42	0.33	1.58	0.52	2.19
Auld	Archie	33.0	0.01	0.01	0.02	0.11	0.02	0.12
Bluff Cove	Arcturus	4.16	0.04	0.23	0.00	1.20	0.02	2.10
Amador	Arden	4.16	0.11	0.20	0.15	1.06	0.20	1.33
Woodruff	Ardis	4.16	0.14	0.15	0.19	1.15	0.30	1.40
Calden	Ardmore	16.0	0.28	0.54	0.40	2.84	0.52	3.32
Palm Springs	Arenas	4.16	0.08	0.13	0.13	0.54	0.21	0.74
Telegraph	Argo	12.0	0.50	0.86	0.67	3.85	1.21	5.31
Triton	Argonaut	12.0	0.22	0.56	0.29	2.63	0.56	4.19
Broadway	Argonne	12.0	0.20	0.41	0.28	2.50	0.35	2.86
Tenaja	Ariel	12.0	0.17	0.78	0.17	3.30	0.31	5.95
Estrella	Aries	12.0	0.64	1.13	1.00	7.84	1.15	9.15
Sepulveda	Arizona	4.16	0.04	0.08	0.01	0.89	0.03	1.17
Solemint	Arlene	16.0	0.43	0.86	0.57	4.32	0.98	6.21
Pedley	Arlington	12.0	0.38	0.81	0.55	3.97	0.81	5.18
Timoteo	Arliss	12.0	0.35	0.76	0.53	4.16	0.68	4.97
Pauba	Armada	12.0	0.28	0.51	0.33	3.66	0.60	5.21
Armijo P.T.	Armijo	12.0	0.06	0.09	0.09	0.46	0.11	0.53
Grangeville	Armona	4.16	0.05	0.06	0.06	0.17	0.17	0.32
Montecito	Armour	4.16	0.05	0.15	0.04	0.85	0.05	1.42
Narod	Armstrong	12.0	0.14	0.21	0.20	1.16	0.32	1.47
Colonia	Arneill	16.0	0.79	0.96	1.18	5.42	1.81	6.60
Imperial	Arnett	12.0	0.17	0.30	0.23	1.59	0.31	1.93
Santa Rosa	Arnez	12.0	0.54	1.12	0.80	4.57	1.19	6.77
MacArthur	Arnold	12.0	0.24	0.62	0.28	3.63	0.33	5.19
Arrington P.T.	Arrington	4.16	0.06	0.05	0.08	0.50	0.18	0.65
Cardiff	Arro-Cardiff-Stoddard	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Limestone	Arsenic	12.0	2.81	4.32	8.91	23.12	21.89	43.47
Idyllwild	Art	2.4	0.02	0.04	0.03	0.24	0.04	0.26
La Fresa	Artisano	16.0	0.99	1.46	1.58	8.48	1.67	8.60
Morro	Artist	12.0	0.37	1.08	0.48	5.55	0.54	8.00
Bryan	Aruba	12.0	0.50	0.94	0.74	5.29	0.86	5.80
Victoria	Arvana	16.0	0.61	0.98	0.73	5.48	1.10	6.91
Fullerton	Ash	4.16	0.15	0.27	0.21	1.51	0.26	1.80
Anaverde	Ashberry	12.0	0.28	0.63	0.39	3.12	0.61	4.73
Archline	Ashford	12.0	0.26	0.38	0.34	2.16	0.78	3.35
Pearl	Ashland	4.16	0.00	0.00	-0.06	0.52	-0.04	0.87
Ashley	Ashley	4.16	0.03	0.08	0.03	0.37	0.04	0.59
Mayflower	Ashmont	4.16	0.10	0.14	0.13	0.84	0.28	1.24
Torrance	Aspen	16.0	1.28	1.65	1.99	10.92	2.49	12.61
Oasis	Assembly	12.0	0.81	1.00	1.19	5.33	1.84	6.39
Alhambra	Asteroid	16.0	0.55	1.25	0.76	7.70	0.88	9.29
Narrows	Aston	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Victor	Astor	12.0	0.65	0.68	0.95	4.13	1.38	5.10
Corona	Astoria	12.0	0.51	1.01	0.74	5.30	1.22	7.26
Estrella	Astrology	12.0	0.41	0.93	0.64	6.06	0.70	6.99
Viejo	Atento	12.0	0.22	0.64	0.16	4.00	0.30	6.11

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Tamarisk	Athel	12.0	0.74	0.98	1.09	4.42	1.86	5.87
Proctor	Athena	12.0	0.47	0.93	0.71	7.49	0.76	10.29
Hathaway	Atherton	12.0	0.36	0.81	0.52	4.89	0.61	5.47
Las Lomas	Atlanta	12.0	0.16	0.44	0.24	2.31	0.24	3.11
Bullis	Atlantic	16.0	0.88	1.08	1.30	5.90	2.02	6.98
Francis	Atlas	12.0	1.08	1.33	1.62	7.08	2.35	8.30
Wakefield	Atmore	16.0	1.29	1.60	1.94	8.33	2.79	9.52
Crown	Atrium	12.0	0.49	1.05	0.78	5.83	0.91	6.28
Pico	Attica	12.0	0.55	0.76	0.88	4.88	0.96	5.73
Culver	Auburn	16.0	0.42	0.73	0.62	4.00	0.82	4.38
O'neill	Audubon	12.0	0.44	0.68	0.59	5.46	0.84	6.71
Alder	Augusta	12.0	0.68	1.16	0.97	5.37	1.72	7.32
Tulare	Aurora	12.0	0.63	0.88	0.87	3.79	1.45	5.13
Vera	Austin	12.0	1.14	1.44	1.72	7.47	2.57	9.12
Autobody	Autobody	4.16	0.05	0.08	0.07	0.46	0.09	0.52
Farrell	Autry	12.0	0.43	0.75	0.63	4.04	0.87	5.52
Skiland	Autumn	12.0	0.21	0.80	0.30	3.65	0.40	4.64
Yorba Linda	Avalanche	12.0	0.28	0.94	0.30	5.39	0.33	7.69
Shandin	Avanti	12.0	0.43	0.99	0.63	4.85	0.95	6.62
Cabrillo	Avco	12.0	0.55	1.24	0.88	7.82	0.91	8.36
Stetson	Avenger	12.0	0.25	0.50	0.35	3.00	0.52	3.93
San Dimas	Avenida	12.0	0.22	0.40	0.29	1.74	0.68	2.95
Aventura P.T.	Aventura	12.0	0.66	1.07	0.98	4.85	1.31	6.05
Narod	Avery	12.0	0.53	0.85	0.78	4.65	1.21	5.75
Stetson	Aviator	12.0	0.55	0.88	0.82	6.10	1.12	7.40
Avocado P.T.	Avocado	4.16	0.02	0.02	0.02	0.07	0.06	0.13
Downey	Avon	4.16	0.15	0.19	0.21	1.17	0.42	1.53
La Mirada	Axel	12.0	0.29	0.39	0.44	2.32	0.62	2.67
Ayersman P.T.	Ayersman	2.4	0.01	0.02	0.01	0.07	0.02	0.09
Rolling Hills	Azalia	4.16	-0.01	-0.01	-0.08	0.58	-0.07	0.87
Puente	Azores	12.0	0.67	1.05	1.01	6.89	1.33	8.73
Indian Wells	Aztec	12.0	0.91	1.51	1.29	5.81	2.57	9.00
Topaz	Azure	4.16	0.00	-0.01	-0.07	0.76	-0.06	0.99
Eric	Baber	12.0	0.53	0.71	0.80	4.10	1.11	4.82
Tenaja	Babylon	12.0	0.25	0.71	0.33	2.65	0.70	4.71
Milliken	Bacardi	12.0	0.89	1.14	1.33	6.80	1.90	8.30
Neptune	Bach	12.0	0.36	0.58	0.53	4.25	0.58	4.68
Walteria	Bachelor	16.0	0.86	0.88	1.28	5.63	1.69	6.46
Firehouse	Backdraft	12.0	0.99	1.31	1.57	7.77	1.80	8.77
Imperial	Bacon	4.16	0.08	0.12	0.11	0.98	0.16	1.22
La Palma	Bacway	12.0	0.26	0.61	0.36	3.30	0.45	3.60
Shandin	Badger	12.0	0.33	0.63	0.48	3.22	0.74	4.14
Badwater P.T.	Badwater	12.0	0.04	0.07	0.05	0.29	0.08	0.35
Bryan	Bahama	12.0	0.27	0.67	0.32	3.09	0.73	5.22
Navy Mole	Bainbridge	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Brea	Baja	12.0	0.38	0.73	0.54	3.61	0.94	4.93
Crown	Balboa	12.0	0.38	0.88	0.55	4.10	0.98	5.66
Fillmore	Balcom	16.0	0.53	0.84	0.74	4.28	1.16	5.22
Eaton	Baldwin	16.0	0.24	0.97	0.18	5.29	0.29	8.24
Upland	Baldy	4.16	0.10	0.16	0.15	0.89	0.26	1.18
Laurel	Ball	12.0	0.68	0.99	1.04	7.46	1.19	9.18
Narrows	Ballard	12.0	1.08	1.88	1.60	10.82	2.12	12.30
Nola	Ballast	16.0	3.37	4.28	8.62	22.41	20.62	40.49
Sepulveda	Ballona	16.0	0.29	0.39	0.46	2.56	0.52	2.76
Moraga	Balloon	12.0	0.37	0.75	0.49	4.34	0.82	6.11
Narod	Ballzak	12.0	0.99	1.29	1.53	7.52	1.88	8.44
Hesperia	Balsam	12.0	0.66	0.90	0.94	3.85	1.72	5.34
Declez	Bamboo	12.0	0.75	1.24	1.18	9.04	1.30	9.90
Citrus	Banana	12.0	0.67	1.06	0.95	5.60	1.55	7.03
Jersey	Bancroft	16.0	2.16	3.64	6.41	20.45	15.07	36.87
Chino	Bandag	12.0	1.87	2.59	4.66	18.95	9.56	29.41
Concho	Bandana	12.0	0.97	1.22	1.41	5.68	2.70	7.59
Francis	Bandera	12.0	0.67	0.81	1.00	4.75	1.47	5.55
Diamond Bar	Bandit	12.0	0.43	0.47	0.48	2.98	1.36	4.96
Niguel	Banjo	12.0	0.33	0.59	0.38	4.49	0.53	5.34
Sunnyside	Banner	12.0	0.33	0.45	0.51	3.00	0.68	3.45
Havasu	Banshee	16.0	0.02	0.03	0.03	0.15	0.04	0.18
Archline	Banyan	12.0	0.40	0.73	0.56	3.57	0.95	4.85
Bryan	Barbados	12.0	0.18	0.45	0.10	3.25	0.26	4.69

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Lark Ellen	Barbara	12.0	0.48	0.56	0.75	4.59	0.87	4.73
Maxwell	Barbee	12.0	0.23	0.35	0.34	2.06	0.48	2.35
Cortez	Barbossa	12.0	0.60	0.78	0.92	4.49	1.23	5.27
Las Lomas	Barcelona	12.0	0.15	0.44	0.13	2.68	0.21	4.02
Bard P.T.	Bard	4.16	0.08	0.15	0.10	1.32	0.12	1.46
Cabrillo	Bardeen	12.0	0.43	0.72	0.56	5.65	0.75	6.60
Merced	Bardo	12.0	0.18	0.24	0.19	0.99	0.71	2.22
Bridge	Barge	4.16	0.07	0.06	0.05	1.01	0.07	1.29
Padua	Barilla	12.0	0.68	1.16	0.92	4.97	2.00	7.72
La Canada	Barleyflats	16.0	0.28	0.45	0.58	3.15	1.11	4.62
Fernwood	Barlow	16.0	1.24	1.59	1.95	8.95	2.18	9.69
Tahiti	Barnacle	16.0	0.30	0.60	0.47	3.22	0.52	3.42
Gale	Baroid	33.0	0.05	0.14	0.09	0.81	0.09	0.90
Upland	Barr	4.16	0.00	0.00	0.00	0.00	0.00	0.00
El Nido	Barracuda	16.0	1.01	1.52	1.62	8.65	1.71	8.76
Covina	Barranca	4.16	0.09	0.15	0.12	0.72	0.26	1.06
Maxwell	Barratt	12.0	0.49	0.79	0.70	4.12	1.19	5.36
Fillmore	Barrington	16.0	0.28	0.44	0.38	1.93	0.65	2.46
Garvey	Bartlett	4.16	0.06	0.09	0.08	0.58	0.09	0.71
Tippecanoe	Barton	4.16	0.06	0.13	0.10	0.68	0.12	0.80
Barwick P.T.	Barwick	2.4	0.00	0.01	0.00	0.03	0.00	0.07
San Antonio	Baseline	12.0	0.70	0.95	0.97	4.07	1.83	5.70
Moulton	Basenji	12.0	0.44	0.90	0.66	4.96	0.83	5.63
Moreno	Basil	12.0	0.44	0.79	0.63	4.33	1.01	5.60
Bayside	Bass	12.0	0.60	1.14	0.92	6.43	1.11	6.90
Niguel	Bassoon	12.0	0.48	1.11	0.77	6.44	0.79	6.54
Bradbury	Bateman	16.0	0.74	0.86	1.11	5.20	1.61	6.01
Santa Barbara	Bath	4.16	0.03	0.05	0.04	0.27	0.05	0.30
Eisenhower	Battalion	12.0	0.85	1.04	1.32	5.44	1.68	5.99
Crest	Bauxite	16.0	0.19	0.51	0.14	3.26	0.21	5.12
State Street	Baxter	12.0	0.29	0.54	0.38	2.53	0.57	2.93
Soquel	Bayberry	12.0	0.36	0.66	0.55	4.23	0.69	4.96
Canyon Lake	Bayliner	12.0	0.16	0.63	0.23	3.39	0.24	5.79
Villa Park	Baylor	12.0	0.42	0.84	0.54	4.97	0.88	6.49
Amador	Bayse	4.16	0.09	0.19	0.13	1.16	0.16	1.39
Paularino	Bayview	4.16	0.05	0.11	0.05	0.83	0.06	1.09
Bunker	Bazooka	12.0	0.91	1.10	1.38	6.83	2.01	8.26
Oceanview	Beach	12.0	0.47	0.58	0.72	3.42	0.89	3.85
Santa Monica	Beachcomber	16.0	0.31	0.63	0.39	3.93	0.50	4.62
Moulton	Beagle	12.0	0.37	0.71	0.53	3.45	0.76	3.89
San Gabriel	Bean	4.16	0.00	0.08	-0.03	0.55	-0.03	1.03
Skylark	Bearcreek	12.0	0.06	0.18	0.06	0.55	0.12	0.87
Colonia	Beardsley	16.0	1.97	2.41	3.11	15.12	3.60	17.15
Zanja	Bearvalley	33.0	0.01	0.02	0.01	0.11	0.01	0.12
Ganesha	Beasley	12.0	0.33	0.43	0.43	2.51	0.86	3.49
Porterville	Beattie	12.0	0.71	0.99	1.07	5.22	1.48	6.33
Wheatland	Beaver	12.0	0.37	0.56	0.56	4.09	0.65	4.98
Gage	Beck	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Newcomb	Becker	12.0	0.37	0.93	0.50	3.88	0.94	6.17
Stetson	Beechcraft	12.0	0.07	0.15	0.11	0.97	0.12	1.20
Kramer	Beechers	2.4	0.03	0.06	0.04	0.34	0.05	0.36
Chestnut	Beechnut	12.0	0.76	1.19	1.16	8.31	1.52	9.65
Archline	Beechwood	12.0	0.33	0.69	0.41	3.64	0.78	5.51
Auld	Beeler	12.0	0.10	0.39	0.06	2.10	0.15	3.58
Victor	Beeline	12.0	0.54	0.64	0.80	3.73	1.24	4.76
Chestnut	Beernut	12.0	0.43	0.92	0.63	5.63	0.69	6.94
Bassett	Beezwax	12.0	0.97	1.14	1.38	4.94	2.35	6.40
Fairview	Begonia	12.0	0.59	0.99	0.90	6.81	1.09	7.89
Orange	Beige	12.0	0.80	1.72	1.28	10.32	1.34	11.14
Las Lomas	Beijing	12.0	0.49	0.87	0.76	5.48	0.85	5.68
Palm Springs	Belardo	4.16	0.21	0.35	0.29	1.32	0.59	2.07
Amalia	Beldon	4.16	0.10	0.17	0.15	1.01	0.20	1.14
Trask	Belfast	12.0	0.74	0.92	1.11	5.16	1.52	6.02
Allen	Bellford	4.16	0.06	0.11	0.06	0.66	0.14	1.05
Newbury	Belpac	16.0	1.09	0.98	1.50	6.36	2.71	8.33
Etiwanda	Belushi	12.0	0.40	0.93	0.50	4.12	1.06	6.84
Colton	Bemis	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Covina	Benbow	4.16	0.09	0.16	0.13	0.73	0.28	1.11
Yucaipa	Bench	12.0	0.65	0.98	0.83	4.33	1.95	6.99

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Dalton	Bender	12.0	0.47	0.73	0.66	3.96	1.20	5.37
Beverly	Benedict	4.16	0.08	0.23	0.12	1.09	0.12	1.63
Walteria	Benhill	16.0	2.08	2.76	4.95	14.94	10.89	24.10
Hathaway	Bennett	12.0	0.36	0.85	0.50	4.84	0.63	5.51
Bain	Bennevis	12.0	0.70	0.91	1.51	6.48	3.00	9.25
Etiwanda	Benny	12.0	0.28	1.42	0.45	8.60	0.45	8.98
Chino	Benson	12.0	0.36	0.69	0.46	3.46	0.87	5.31
Ivar	Bentel	4.16	0.08	0.10	0.11	0.71	0.20	0.93
Alessandro	Benton	12.0	0.82	1.38	1.14	6.61	1.79	8.21
Oldfield	Bentree	4.16	0.07	0.08	0.09	0.85	0.16	1.10
Oasis	Beone	12.0	0.39	0.45	0.61	3.32	0.71	3.65
Arro	Berkley	4.16	0.14	0.24	0.20	1.25	0.29	1.50
Arroyo	Berkshire	4.16	0.21	0.37	0.24	1.15	0.54	2.05
Fullerton	Berlin	12.0	0.56	1.00	0.82	5.61	1.13	6.45
Saugus	Bermite	16.0	1.68	2.16	2.62	12.17	3.27	13.58
Bryan	Bermuda	12.0	0.37	0.72	0.52	3.93	0.73	4.76
Linden	Bernard	4.16	0.10	0.16	0.15	1.06	0.16	1.22
Marion	Bernice	12.0	0.46	0.94	0.73	5.65	0.79	5.96
Flanco	Berry	4.16	0.14	0.17	0.22	1.02	0.27	1.13
Cabrillo	Bertea	12.0	0.52	1.23	0.82	7.21	0.88	7.55
Marion	Bertha	12.0	0.28	0.59	0.34	3.90	0.44	4.98
Redondo	Beryl	4.16	0.05	0.09	0.02	0.78	0.09	1.05
Bessemer P.T.	Bessemer	12.0	0.00	0.00	0.01	0.02	0.01	0.03
Telegraph	Beta	12.0	0.70	1.09	1.01	6.13	1.59	7.63
Bartolo	Bexley	4.16	0.12	0.17	0.18	1.12	0.28	1.37
Padua	Bianco	12.0	0.67	0.84	0.86	3.90	2.31	6.47
Goleta	Bidder	16.0	0.07	0.13	0.08	0.47	0.16	0.68
Temple	Bidwell	4.16	0.10	0.12	0.14	0.74	0.26	0.96
Live Oak	Bigcone	12.0	0.39	0.57	0.91	4.44	1.90	6.62
Lucas	Bigelow	12.0	0.36	0.66	0.53	3.96	0.67	4.39
Forest Home	Bigfalls	2.4	0.04	0.07	0.08	0.43	0.10	0.46
Bigfoot P.T.	Bigfoot	4.16	0.02	0.02	0.02	0.11	0.03	0.13
Biggs P.T.	Biggs	4.16	0.03	0.06	0.03	0.26	0.07	0.43
Santa Rosa	Bighorn	12.0	1.24	1.56	1.73	5.56	3.99	8.55
Blythe City	Bigler	4.8	0.08	0.11	0.12	0.50	0.17	0.61
Little Rock	Bigpines	12.0	0.37	0.51	0.59	3.75	0.64	4.48
Declez	Bigrigg	12.0	0.79	0.97	1.42	7.54	1.95	8.62
Chatsworth	Bigrock	16.0	0.46	0.74	0.78	5.29	1.09	6.66
Layfair	Bill	12.0	1.72	2.20	4.37	12.41	10.08	21.32
Fairview	Billings	12.0	0.44	0.79	0.64	4.21	0.86	4.75
Fogarty	Billy	12.0	0.07	0.20	0.10	1.02	0.13	1.46
Line Creek	Billycreek	4.16	0.01	0.01	0.01	0.05	0.01	0.06
Rosemead	Bilton	16.0	0.56	0.88	0.80	5.69	1.11	6.73
Maraschino	Bing	12.0	0.66	1.12	0.94	6.68	1.32	8.37
Johanna	Bingo	12.0	0.24	0.36	0.37	2.66	0.46	3.10
Walnut	Binney	12.0	0.52	0.52	0.72	3.61	1.18	5.43
Telegraph	Biola	12.0	0.30	0.77	0.41	4.42	0.51	5.81
Stetson	Biplane	12.0	0.33	0.92	0.43	4.17	0.62	6.21
Tamarisk	Birch	12.0	0.41	0.65	0.57	2.93	1.12	4.49
Mt. Tom	Birchim	12.0	0.09	0.25	0.11	0.96	0.15	1.28
Oak Park	Birchwood	16.0	0.60	1.28	0.84	6.63	1.23	8.16
Bowl	Bird	12.0	0.40	0.84	0.63	4.67	0.72	4.86
Oceanview	Bishop	12.0	1.01	1.30	1.59	7.30	1.82	7.97
Camden	Bismuth	12.0	0.57	1.10	0.85	6.83	1.01	7.55
Lampson	Bison	12.0	0.59	1.36	0.88	7.75	1.03	8.30
Nelson	Bissell	12.0	0.36	0.71	0.50	3.58	0.77	4.73
Silver Spur	Bit	12.0	0.54	1.04	0.82	4.52	1.14	6.28
Soquel	Bittern	12.0	0.41	0.46	0.47	3.25	1.30	5.43
Orange	Black	12.0	0.35	0.69	0.54	4.05	0.64	4.50
Lockheed	Blackbird	16.0	0.41	0.83	0.59	5.08	0.71	6.08
El Sobrante	Blackburn	12.0	0.52	0.74	0.63	3.42	1.68	5.80
Gavilan (115)	Blackfoot	12.0	0.68	1.35	0.98	6.77	1.44	7.68
Rush	Blackgold	16.0	0.00	0.00	0.00	0.00	0.00	0.00
Shawnee	Blackhawk	12.0	0.77	0.84	1.03	5.13	1.97	7.39
Glen Avon	Blackhills	12.0	0.41	0.90	0.58	4.16	0.93	5.62
Torrance	Blackjack	16.0	0.65	0.93	1.05	6.00	1.12	6.50
Liberty	Blackstone	12.0	0.57	1.16	0.74	4.76	1.71	7.38
Lunada	Blackwater	4.16	0.02	0.00	0.03	0.10	0.07	0.16
Imperial	Blaine	12.0	0.38	0.48	0.58	2.64	0.79	3.05

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
La Fresa	Blake	16.0	0.84	1.52	1.20	9.09	1.42	10.03
Columbine	Blanca	12.0	0.17	0.23	0.27	1.19	0.49	1.46
Repetto	Blanchard	16.0	0.52	1.00	0.71	5.23	0.98	6.25
Center	Blanket	12.0	1.20	1.62	3.20	9.59	7.01	15.96
Firehouse	Blaze	12.0	0.45	0.58	0.73	5.42	0.75	6.28
Stadler	Bleacher	12.0	0.19	0.55	0.22	3.14	0.31	4.75
Neenach	Bledsoe	12.0	0.16	0.21	0.24	1.43	0.32	1.67
Rush	Bleeker	16.0	0.00	0.00	0.00	0.00	0.00	0.00
Coffee	Blend	12.0	0.83	1.15	1.24	5.82	1.85	7.40
Nola	Blimp	16.0	1.46	1.66	2.16	10.37	3.42	12.23
Pixley	Blinker	12.0	0.39	0.50	0.61	4.11	0.75	5.19
Stadler	Blitz	12.0	0.32	0.87	0.42	4.65	0.55	6.41
Yorba Linda	Blizzard	12.0	0.32	0.73	0.36	3.78	0.80	5.93
Walteria	Blocker	16.0	0.55	0.86	0.64	6.28	0.86	7.69
Topaz	Bloodstone	4.16	0.11	0.20	0.16	1.07	0.19	1.23
Victoria	Blossom	16.0	0.59	1.14	0.75	5.41	1.14	6.55
Desert Outpost	Blowsand	12.0	0.38	0.46	0.79	3.64	1.34	4.98
Orange	Blue	12.0	0.34	0.60	0.50	3.69	0.64	4.20
Citrus	Blueberry	12.0	0.81	0.98	1.20	5.06	1.90	6.10
Perez	Bluecrest	4.16	0.02	0.04	0.04	0.27	0.04	0.32
Blue Cut P.T.	Bluecut	12.0	0.10	0.18	0.15	1.13	0.19	1.39
La Mirada	Bluefield	12.0	0.43	0.61	0.67	3.81	0.79	3.96
El Nido	Bluegill	16.0	1.20	1.57	1.73	8.05	3.10	10.02
Jefferson	Bluemoon	12.0	0.58	0.99	0.82	5.05	1.58	7.18
Blue Ridge P.T.	Blueridge	2.4	0.01	0.01	0.05	0.12	0.14	0.23
Thunderbird	Blueskies	4.8	0.00	0.00	0.00	0.00	0.00	0.00
North Oaks	Boa	16.0	0.75	1.27	1.12	7.45	1.39	7.87
Blythe City	Boat	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Bloomington	Bobber	12.0	0.28	0.46	0.43	3.22	0.47	3.48
Chase	Bobbit	12.0	0.44	1.00	0.55	4.90	1.10	7.76
Merced	Bobby	12.0	0.68	0.91	0.89	4.19	2.08	6.90
Wheatland	Bobcat	12.0	0.29	0.35	0.46	2.67	0.52	2.91
Skiland	Bobsled	12.0	0.23	0.87	0.35	4.23	0.39	5.12
Skylark	Bodkin	12.0	0.18	0.30	0.24	1.58	0.47	2.35
Lennox	Boeing	16.0	0.76	1.43	1.15	7.89	1.30	8.60
Movie	Bogart	16.0	0.71	1.35	1.08	8.19	1.34	9.15
Defrain	Bogey	12.0	0.11	0.23	0.16	0.87	0.26	1.34
Jefferson	Bohemia	12.0	0.24	0.66	0.22	2.95	0.74	5.76
Savage	Boise	12.0	0.83	1.30	1.28	7.10	1.52	8.62
Fremont	Boland	4.16	0.14	0.23	0.22	1.49	0.24	1.71
Ely	Bolivia	12.0	1.22	1.78	3.57	10.52	8.32	18.95
Corona	Bollero	12.0	0.60	0.97	0.81	4.78	1.70	7.12
Alder	Bolor	12.0	0.57	1.40	0.88	9.20	0.93	10.34
Jersey	Bolton	16.0	0.48	0.78	0.68	4.57	0.84	5.38
Eisenhower	Bombardier	12.0	0.57	0.79	0.77	2.87	1.86	4.81
Bloomington	Bombay	12.0	0.17	0.61	0.27	3.71	0.30	3.98
Kernville	Bonanza	12.0	0.39	0.54	0.58	2.53	0.90	3.14
Watson	Bond	12.0	0.06	0.16	0.10	1.18	0.10	1.31
Nuevo	Bonge	12.0	0.43	0.56	0.58	3.18	1.37	5.43
San Dimas	Bonita	12.0	1.12	1.37	1.69	6.67	2.46	7.58
Topanga	Bonnell	4.16	0.02	0.07	0.01	0.35	0.02	0.59
Duarte	Bonnie	4.16	0.10	0.23	0.14	1.04	0.26	1.60
Live Oak	Bontanic	12.0	0.33	0.38	0.48	1.84	0.79	2.28
Narod	Bonview	12.0	0.33	0.52	0.49	2.86	0.74	3.47
Tortilla	Book	33.0	0.00	0.00	0.05	0.00	0.12	0.00
Columbine	Boone	12.0	0.15	0.24	0.24	1.72	0.27	1.80
Lindsay	Booster	12.0	0.34	0.49	0.49	2.41	0.68	3.08
Diamond Bar	Boothill	12.0	0.87	1.06	1.32	5.39	1.85	6.14
Acton	Bootlegger	12.0	0.44	0.92	0.57	4.31	0.97	6.76
Archibald	Borba	12.0	0.51	0.65	0.77	3.52	1.17	4.10
Newbury	Borchard	16.0	1.19	1.26	1.70	6.77	2.79	8.45
O'neill	Borchers	12.0	0.34	0.64	0.41	4.41	0.71	6.03
Pauba	Bordeaux	12.0	0.22	0.45	0.27	2.99	0.49	4.32
Ditmar	Borden	4.16	0.04	0.09	0.03	0.60	0.05	0.92
Jefferson	Border	12.0	0.91	1.12	1.36	6.51	2.02	7.90
Wimbledon	Borg	12.0	0.40	0.51	0.65	4.10	0.70	4.65
Bandini	Boris	16.0	0.35	0.44	0.54	2.69	0.66	3.11
Modena	Borneo	12.0	0.26	1.02	0.25	4.62	0.39	7.40
Sunnyside	Bort	12.0	0.20	0.35	0.30	2.70	0.36	3.34

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Cortez	Bosco	12.0	0.60	0.74	0.90	3.61	1.31	4.19
Graham	Boston	4.16	0.10	0.13	0.15	0.87	0.16	0.94
Highland	Boulder	12.0	0.37	0.81	0.48	4.02	0.92	6.29
Linden	Boulevard	4.16	0.07	0.13	0.11	0.84	0.12	0.98
Solemint	Bouquet	16.0	0.14	0.41	0.17	1.99	0.25	2.94
Pico	Bow	12.0	0.26	1.08	0.41	7.04	0.44	8.25
Strathmore	Bowen	12.0	0.85	1.08	1.18	4.60	2.18	6.13
Pioneer	Bowie	12.0	0.82	1.03	1.28	5.97	1.53	6.70
Downs	Bowman	12.0	0.59	0.86	0.84	4.59	1.42	6.08
Goldtown	Boxcar	12.0	0.72	0.90	1.08	5.11	1.46	5.85
Center	Boxer	12.0	0.83	1.06	1.26	6.21	1.77	7.05
Calectric	Boxspring	33.0	0.10	0.29	0.17	2.00	0.17	2.47
Layfair	Boyalta	12.0	0.92	1.11	1.36	5.48	2.07	6.61
Stadium	Boyd	12.0	0.67	1.16	0.95	6.93	1.40	8.57
Sunnyside	Boyer	12.0	0.09	0.14	0.14	0.91	0.15	0.98
Fruitland	Boyle	4.16	0.02	0.02	0.02	0.10	0.04	0.12
Cucamonga	Boynton	12.0	0.67	0.93	1.06	8.69	1.15	10.64
Villa Park	Boysen	12.0	0.60	1.08	0.82	5.19	1.24	6.30
Layfair	Brackett	12.0	0.91	1.09	1.36	6.08	2.04	7.43
Newcomb	Bradley	12.0	0.27	0.56	0.40	3.26	0.56	4.22
Del Amo	Bradshaw	12.0	0.44	0.65	0.71	4.23	0.72	4.25
Allen	Braeburn	4.16	0.04	0.20	0.03	0.99	0.03	1.74
Playa	Braemer	4.16	0.00	0.00	-0.07	0.80	-0.05	1.11
Harvard	Bragdon	12.0	0.11	0.23	0.15	0.92	0.21	1.24
Bovine	Brahma	12.0	0.35	0.27	0.43	2.33	0.89	3.38
Lucas	Brakebill	12.0	0.36	0.87	0.48	4.51	0.63	5.63
Railroad	Brakeman	12.0	0.67	0.75	0.85	3.51	2.08	6.19
Torrance	Bramble	16.0	0.37	0.48	0.60	2.88	0.62	3.13
Santa Susana	Brand	16.0	1.15	1.45	1.65	6.51	2.62	8.15
Fullerton	Brashears	12.0	0.84	1.80	1.31	10.01	1.56	10.82
Alhambra	Braun	16.0	0.42	0.84	0.63	5.59	0.70	6.06
Archibald	Bravon	12.0	0.26	0.43	0.25	3.31	0.62	5.14
Bowl	Brayton	4.16	0.20	0.23	0.29	1.19	0.50	1.46
Bryan	Brazil	12.0	0.28	0.54	0.38	3.20	0.60	4.32
Dryden P.T.	Breakwater	12.0	0.00	0.00	-0.01	-0.03	-0.01	-0.02
Merced	Bren	12.0	0.25	0.83	0.32	4.64	0.50	5.59
Moorpark	Brennan	16.0	0.24	0.55	0.25	3.94	0.31	5.47
Garfield	Brent	4.16	0.05	0.11	0.07	0.63	0.08	0.84
Los Cerritos	Brethren	12.0	0.34	0.67	0.49	3.37	0.67	3.67
Atwood	Breting	12.0	0.41	0.55	0.54	3.56	1.07	4.94
Mira Loma	Brewer	12.0	1.02	1.36	1.56	6.81	2.09	7.39
Bandini	Brickyard	16.0	1.06	1.32	1.62	7.95	2.14	9.08
La Habra	Bride	12.0	0.73	1.33	1.01	6.10	1.55	6.96
Stirrup	Bridle	4.16	0.03	0.18	0.02	0.75	0.02	1.41
Neptune	Brine	12.0	0.40	0.91	0.57	5.45	0.67	6.04
Pico	Brink	12.0	0.13	0.22	0.21	2.69	0.23	4.43
Model P.T.	Brinkley	12.0	0.39	0.67	0.56	3.13	1.02	4.17
Sullivan	Brittan	12.0	0.59	0.71	0.90	3.73	1.21	4.16
Calcity 'A'	Brittlebush	12.0	0.22	0.35	0.48	2.78	0.85	3.80
Gould	Broadcast	33.0	0.01	0.01	0.01	0.10	0.01	0.16
Broadcom P.T.	Broadcom	2.4	0.01	0.01	0.01	0.09	0.01	0.09
Narrows	Bronco	12.0	0.47	1.04	0.67	6.26	0.78	7.50
Sharon	Brookhill	4.16	-0.01	0.03	-0.05	0.23	-0.03	0.60
Brookings P.T.	Brookings	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Rush	Brookline	16.0	1.20	1.83	1.66	9.36	2.58	11.55
Belvedere	Brooklyn	4.16	0.14	0.23	0.19	1.37	0.24	1.54
Amador	Brooks	4.16	0.15	0.23	0.22	1.34	0.34	1.64
Redlands	Brookside	4.16	0.10	0.11	0.13	0.69	0.29	1.00
Colonia	Broome	16.0	0.33	0.44	0.52	2.99	0.60	3.34
Corona	Brotherton	12.0	0.66	0.67	0.90	4.53	1.86	6.50
Brown P.T.	Brown	4.16	0.13	0.19	0.14	0.38	0.30	0.71
Blythe City	Brucepark	4.8	0.09	0.11	0.16	0.88	0.22	1.21
Victor	Brucite	12.0	0.55	0.66	0.80	3.27	1.44	4.40
Auld	Brumfield	12.0	0.07	0.29	0.03	1.49	0.10	2.68
Alhambra	Brunner	4.16	0.03	0.04	0.00	0.77	0.02	0.99
Padua	Bruno	12.0	0.49	0.66	0.56	3.24	1.70	6.11
Maxwell	Brutte	12.0	0.63	1.24	0.93	6.55	1.22	7.59
La Fresa	Bryant	16.0	0.48	0.68	0.74	3.49	1.04	3.87
Amador	Bryce	16.0	0.96	1.66	1.42	9.91	1.88	11.44

SOUTHERN CALIFORNIA EDISON
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			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
San Dimas	Brydon	12.0	0.46	0.60	0.63	3.08	1.33	4.14
Redlands	Brynmawr	12.0	0.30	0.48	0.53	3.42	0.85	4.87
La Mirada	Buck	12.0	0.68	0.88	1.10	5.38	1.16	5.45
Gonzales	Buckaroo	16.0	1.27	1.41	1.83	7.59	3.08	9.20
Ivyglen	Buckboard	12.0	0.36	0.59	0.52	3.46	0.89	4.75
Fillmore	Buckhorn	16.0	0.82	1.33	1.19	7.59	1.69	8.86
Royal	Buckner	16.0	0.35	0.99	0.40	5.47	0.59	7.90
Hesperia	Buckthorn	12.0	0.55	0.83	0.80	4.35	1.35	5.90
Pixley	Budd	12.0	1.01	1.66	2.20	11.69	4.29	17.27
Howard	Budlong	4.16	0.17	0.28	0.25	1.59	0.29	1.82
Center	Buffalo	12.0	0.23	0.47	0.30	2.27	0.44	2.66
Chatsworth	Buffer	16.0	0.14	0.79	0.11	3.12	0.23	5.82
Greening	Buford	12.0	0.32	0.25	0.45	2.10	0.76	2.65
Gale	Bug	33.0	0.35	0.73	0.56	4.48	0.57	4.85
Buggy U.G.S.	Buggy	4.16	0.02	0.04	0.02	0.14	0.03	0.24
Eisenhower	Buldge	12.0	0.63	0.98	0.91	4.46	1.63	6.42
Moulton	Bulldog	12.0	0.63	1.05	0.86	4.80	1.44	6.02
Pomona	Bulletin	4.16	0.13	0.17	0.20	0.87	0.25	0.98
Triton	Bullhead	12.0	0.10	0.29	0.11	1.93	0.14	2.78
Sullivan	Bullocks	12.0	0.50	0.60	0.73	3.29	1.03	3.83
Mascot	Bullpup	12.0	0.33	0.94	0.45	4.34	0.80	6.40
Skylark	Bundy	12.0	0.27	0.66	0.39	3.59	0.48	4.62
Sepulveda	Bungalow	16.0	0.70	1.33	1.13	8.07	1.15	8.61
Beverly	Bunny	16.0	0.46	1.12	0.74	6.38	0.79	6.55
Ganesha	Burdick	4.16	0.11	0.17	0.16	0.99	0.20	1.19
Bicknell	Burger	4.16	0.06	0.09	0.08	0.48	0.13	0.56
Pepper	Burgundy	12.0	0.37	0.63	0.53	3.81	0.63	4.58
Holiday	Burkett	4.16	0.28	0.37	0.38	1.46	0.87	2.33
Yukon	Burleigh	4.16	0.08	0.13	0.12	0.76	0.14	0.86
Royal	Burleson	16.0	0.68	1.50	0.93	7.45	1.58	10.90
Jersey	Burma	16.0	1.00	1.28	1.54	8.26	2.05	9.36
Yucaipa	Burns	12.0	0.36	0.52	0.46	2.84	1.06	4.39
Yucca	Burntmountain	12.0	0.56	0.69	0.96	4.93	1.45	7.22
Lindsay	Burr	12.0	0.37	0.82	0.45	3.37	0.76	4.78
Hanford	Burris	12.0	0.90	1.20	1.36	6.37	2.01	7.82
Tortilla	Burrito	12.0	0.44	0.87	0.65	4.37	0.87	5.30
Ridgecrest	Burroughs	4.8	0.07	0.13	0.10	0.63	0.16	0.78
Porterville	Burton	12.0	0.62	1.18	0.90	5.14	1.34	7.31
Mariposa	Burum	12.0	0.31	0.44	0.46	2.59	0.58	3.00
Savage	Burwood	12.0	0.71	1.00	1.06	5.45	1.52	6.85
Rector	Bush	12.0	0.22	0.43	0.32	3.06	0.39	3.35
Oceanview	Bushard	12.0	0.64	0.85	0.88	5.45	1.30	6.93
East Barstow	Business	4.16	0.01	0.02	0.02	0.16	0.02	0.19
Sepulveda	Butane	16.0	2.51	3.91	7.38	21.51	17.91	39.03
Carmenita	Butler	12.0	0.52	0.72	0.82	5.83	0.95	6.83
Rosamond	Butte	12.0	0.38	0.65	0.52	3.72	0.77	5.18
Soquel	Butterfield	12.0	0.32	0.72	0.43	4.88	0.52	6.04
Chestnut	Butternut	12.0	0.41	0.70	0.61	3.95	0.81	4.50
Thousand Oaks	Byer	16.0	0.72	1.40	0.99	7.53	1.45	9.10
Stoddard	Byron	4.16	0.00	0.01	0.01	0.03	0.01	0.03
Holiday	Caballeros	4.16	0.21	0.27	0.30	1.16	0.57	1.62
Bain	Cabana	12.0	0.32	0.59	0.49	3.79	0.60	4.64
Pepper	Cabernet	12.0	0.22	0.39	0.31	1.81	0.52	2.34
San Antonio	Cable	12.0	0.92	1.14	1.39	5.66	2.00	6.38
Railroad	Caboose	12.0	0.47	0.61	0.60	3.47	1.23	5.74
Madrid	Cabrillo	4.16	0.03	0.04	0.04	0.38	0.05	0.44
Vegas	Cachuma	16.0	0.35	0.85	0.25	6.90	0.45	8.94
Colton	Cactus	12.0	0.08	0.33	0.13	2.30	0.13	2.86
Westgate	Cadbury	4.16	0.11	0.12	0.15	0.89	0.31	1.17
Gilbert	Caddy	12.0	0.14	0.40	0.05	3.53	0.15	5.33
Potrero	Cadena	16.0	0.53	0.65	0.78	3.43	1.06	3.91
Narrows	Cadillac	12.0	0.82	1.70	1.25	9.20	1.69	10.97
Newmark	Cadiz	4.16	0.07	0.04	0.07	0.61	0.15	0.81
Camden	Cadmium	12.0	0.45	0.89	0.59	4.11	0.89	4.95
Wakefield	Cadway	16.0	1.27	1.45	1.77	6.44	3.21	8.40
Haskell	Caesar	16.0	0.39	0.89	0.41	4.39	1.04	7.53
Coffee	Cafe	12.0	0.49	0.84	0.72	4.10	0.99	5.53
Padua	Cagli	12.0	0.34	0.69	0.45	3.82	0.76	5.48
Movie	Cagney	16.0	0.38	0.84	0.56	4.57	0.74	5.06

Substation	Distribution Circuit	Voltage (kV)	Scenario 1 Coincident Capacity (MW)	Scenario 1 Total Capacity (MW)	Scenario 2 Coincident Capacity (MW)	Scenario 2 Total Capacity (MW)	Scenario 3 Coincident Capacity (MW)	Scenario 3 Total Capacity (MW)
Indian Wells	Cahuilla	12.0	0.72	1.04	1.07	4.85	1.64	6.20
Lindsay	Cairns	12.0	0.66	1.46	1.41	7.44	3.01	11.93
Redlands	Cajon	4.16	0.07	0.06	0.07	0.47	0.24	0.90
Valdez	Calabasas	16.0	0.53	0.99	0.67	3.85	1.69	6.99
Declez	Calabash	12.0	0.71	0.94	1.14	6.23	1.19	7.44
Calamar P.T.	Calamar	12.0	0.09	0.17	0.13	0.68	0.27	0.99
Beverly	Calarest	4.16	0.09	0.12	0.14	0.64	0.19	0.73
Calcadia P.T.	Calcadia	12.0	0.00	0.01	0.01	0.02	0.01	0.03
Limestone	Calcium	12.0	0.29	0.74	0.32	5.35	0.39	6.74
Visalia	Caldwell	12.0	0.65	1.01	0.94	4.62	1.50	6.38
Newhall	Calgrove	16.0	0.45	1.39	0.64	6.26	0.81	8.93
Palmdale	Caliber	12.0	0.53	0.84	0.75	4.63	1.38	6.30
Sullivan	Calico	12.0	0.61	1.00	0.90	5.81	1.08	6.44
Cummings	Caliente	12.0	0.41	0.54	0.54	2.75	0.96	3.78
Chase	California	12.0	0.25	1.08	0.27	4.61	0.43	8.08
Yucaipa	Calimesa	12.0	0.46	0.89	0.69	5.19	0.94	6.25
Barre	Calla	12.0	0.60	1.11	0.79	6.57	1.03	8.12
Hemet	Calland	12.0	0.13	0.29	0.20	1.71	0.23	2.09
Moraga	Callaway	12.0	0.56	1.04	0.82	5.34	1.13	6.10
Tipton	Callison	12.0	0.57	0.74	0.88	5.83	1.21	7.55
Little Rock	Callivalli	12.0	0.30	0.47	0.47	3.63	0.51	4.72
Neptune	Calm	12.0	0.42	0.49	0.63	2.83	0.92	3.24
Chino	Calmen	12.0	0.77	1.15	1.17	7.12	1.53	8.75
Wave	Calol	12.0	0.62	1.12	0.87	7.16	1.01	8.00
San Dimas	Calora	12.0	1.74	2.28	4.60	12.80	10.24	20.90
Layfair	Calpoly	12.0	0.56	0.70	1.01	4.71	1.57	5.68
Live Oak	Calspar	12.0	0.15	0.67	0.09	3.33	0.22	5.67
Shandin	Calstate	12.0	0.42	1.19	0.67	7.27	0.70	8.18
Laguna Bell	Calstrip	16.0	0.70	0.93	1.17	5.99	1.44	6.29
Padua	Calvo	12.0	0.56	0.88	0.79	4.74	1.39	6.39
Bassett	Calypso	12.0	0.48	0.65	0.70	3.31	1.14	4.26
Mayberry	Cambridge	12.0	0.19	0.56	0.28	2.98	0.32	4.21
Anita	Camellia	16.0	0.25	0.66	0.32	4.08	0.37	5.58
Bain	Cameo	12.0	0.72	0.96	1.06	5.62	1.57	7.24
Redondo	Caminoreal	4.16	0.10	0.13	0.15	0.88	0.17	1.05
Camp Angelus P.T.	Campangelus	2.4	0.03	0.05	0.04	0.33	0.05	0.39
Nugget	Campanula	25.0	0.35	0.61	0.52	3.20	0.71	4.36
Camp Baldy P.T.	Campbaldy	2.4	0.02	0.03	0.03	0.21	0.03	0.25
Porterville	Campbell	12.0	0.50	1.09	0.68	4.51	0.93	6.63
Camp Nelson P.T.	Campnelson	4.16	0.05	0.07	0.07	0.54	0.10	0.89
Cottonwood	Camprock	33.0	0.02	0.13	0.03	2.67	0.04	5.26
Upland	Campus	12.0	0.66	0.97	0.93	4.69	1.81	6.34
Belvedere	Camy	4.16	0.18	0.28	0.26	1.53	0.32	1.75
Nelson	Canal	33.0	0.11	0.18	0.12	0.56	0.24	0.81
Canalino P.T.	Canalino	2.4	0.01	0.01	0.01	0.06	0.01	0.06
Tulare	Canby	12.0	0.47	1.08	0.66	5.23	1.04	6.77
Estrella	Cancer	12.0	0.68	1.24	1.05	8.32	1.21	9.61
Brea	Cancun	12.0	0.38	0.51	0.59	4.50	0.63	4.75
Somerset	Candle	12.0	1.22	1.54	1.87	8.58	2.51	9.79
Anaverde	Candleberry	12.0	0.79	1.05	1.20	5.25	1.66	6.09
Weldon	Canebrake	12.0	0.15	0.22	0.21	1.11	0.32	1.43
Lakewood	Canehill	4.16	0.01	-0.01	-0.03	0.63	-0.01	0.86
Casitas	Canet	16.0	1.04	1.18	1.55	7.88	2.19	10.23
Laguna Bell	Canning	16.0	0.45	0.69	0.72	4.85	0.79	4.97
Bolsa	Canoe	12.0	0.73	0.63	1.00	4.53	1.88	6.03
Palm Canyon	Cantina	12.0	0.57	1.11	0.84	4.90	1.22	7.03
Los Cerritos	Canton	4.16	0.08	0.15	0.09	1.24	0.11	1.53
Capanero P.T.	Capanero	2.4	0.02	0.06	0.03	0.22	0.04	0.34
Costa Mesa	Cape	4.16	0.02	0.09	-0.03	0.89	-0.02	1.40
Triton	Capelin	12.0	0.25	0.57	0.35	3.69	0.40	4.57
Lucas	Capetown	12.0	0.42	0.80	0.61	4.14	0.81	4.56
Newmark	Capitol	4.16	0.07	0.09	0.10	0.75	0.16	0.92
Artesia	Caponhurst	4.16	0.13	0.18	0.19	1.20	0.26	1.37
Broadway	Capri	12.0	0.32	0.62	0.45	3.69	0.58	4.18
Estrella	Capricorn	12.0	0.03	0.07	0.04	0.39	0.05	0.48
Culver	Capstan	16.0	0.12	0.19	0.14	0.60	0.26	0.85
Cardiff	Capsule-Cardiff	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Carancho P.T.	Carancho	12.0	0.17	0.51	0.23	2.13	0.28	3.20
Vestal	Caratan	12.0	0.22	0.38	0.33	2.69	0.40	3.24

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Greening	Caravel	12.0	0.82	1.02	1.27	6.89	1.59	7.65
Bunker	Carbine	12.0	0.52	0.89	0.76	5.22	1.08	6.46
Goldtown	Carbon	12.0	0.43	0.69	0.65	4.35	0.76	4.74
Cardiff	Cardiff-Greenspot-Santaanariver3	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Cardiff	Cardiff-Santaanariver3	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Cardiff	Cardiff-Stoddard	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Cardinal P.T.	Cardinal	2.4	0.02	0.09	0.03	0.48	0.03	0.58
Mt. Vernon	Carey	4.16	0.09	0.17	0.14	1.04	0.18	1.20
Lakewood	Carfax	4.16	0.04	0.08	0.02	0.87	0.04	1.27
Seabright	Cargo	12.0	0.26	0.48	0.38	2.59	0.49	2.92
Moraga	Cariso	12.0	0.37	0.75	0.53	4.25	0.80	5.70
San Dimas	Carlet	12.0	0.41	0.86	0.54	4.41	0.89	5.95
Lynwood	Carlin	4.16	0.18	0.30	0.27	1.78	0.31	2.04
Atwood	Carlton	12.0	0.25	0.40	0.34	1.94	0.72	2.89
San Vicente	Carlyle	4.16	0.02	0.00	-0.02	0.32	0.04	0.59
Newcomb	Carmel	12.0	0.26	0.54	0.37	3.23	0.56	4.46
Shandin	Carmelita	12.0	0.32	0.52	0.50	3.62	0.56	3.94
Barre	Carnation	12.0	0.69	1.13	1.05	7.30	1.28	7.97
Gonzales	Carnegie	16.0	0.86	0.75	1.18	5.20	2.30	6.48
Victoria	Carnelian	16.0	0.70	1.65	1.04	9.71	1.23	10.83
Lighthipe	Caro	12.0	0.82	1.02	1.24	5.98	1.77	6.66
Parkwood	Carob	12.0	0.52	0.93	0.76	5.51	0.98	6.28
Del Rosa	Carpenter	12.0	1.30	2.21	3.83	10.81	9.11	18.54
Carpinteria	Carpoil	16.0	0.48	0.94	0.63	5.20	0.85	6.03
Puente	Carr	12.0	0.20	0.39	0.27	2.45	0.31	3.22
Silver Spur	Carriage	12.0	0.84	1.28	1.24	5.81	2.11	7.99
Palm Canyon	Carribean	12.0	0.47	0.72	0.68	3.07	1.19	4.34
Pico	Carrier	12.0	0.00	0.00	0.00	0.01	0.00	0.01
Gilbert	Cart	12.0	0.60	0.93	0.89	6.66	1.11	7.68
Howard	Carter	4.16	0.12	0.26	0.17	1.35	0.19	1.77
Tulare	Cartmill	12.0	0.47	1.08	0.67	5.30	1.14	6.76
Oxnard	Carty	4.16	0.04	0.08	0.05	0.43	0.07	0.49
Quinn	Carver	12.0	0.44	0.54	0.68	4.08	0.87	4.94
Car Wash P.T.	Carwash	4.16	0.04	0.05	0.13	0.64	0.32	1.44
Redlands	Casaloma	4.16	0.07	0.11	0.11	0.89	0.12	1.06
Wimbledon	Casals	12.0	0.54	0.62	0.77	3.99	1.33	5.16
Pitman	Cascada	12.0	0.05	0.07	0.06	0.20	0.11	0.33
Cascade P.T.	Cascade	12.0	0.12	0.55	0.15	2.10	0.17	3.54
Elsinore	Case	33.0	0.00	0.01	0.00	0.03	0.01	0.03
San Marcos	Casey	16.0	0.13	0.22	0.16	1.10	0.24	1.32
Alder	Casmalia	12.0	0.51	0.99	0.72	5.49	1.10	7.34
Casper P.T.	Casper	4.16	0.01	0.01	0.01	0.03	0.02	0.04
Cameron	Caspian	12.0	0.24	0.40	0.33	2.02	0.44	2.41
Santa Susana	Cassidy	16.0	0.92	1.09	1.37	5.52	2.02	6.28
Gisler	Cassini	12.0	0.45	0.70	0.72	4.43	0.77	4.72
Modoc	Castillo	4.16	0.09	0.18	0.10	1.05	0.15	1.37
Castle P.T.	Castle	4.16	0.02	0.06	0.00	0.38	0.01	0.65
Edwards	Castlebutte	33.0	0.20	0.27	0.32	1.56	0.32	1.58
Big Bend Bia	Castlerock	12.0	0.13	0.16	0.19	0.77	0.30	0.92
Wakefield	Castro	16.0	0.81	0.91	1.15	4.91	1.94	6.09
Fremont	Caswell	16.0	0.59	0.78	0.91	5.71	1.17	6.89
Redondo	Catalina	4.16	0.01	0.02	-0.03	0.77	-0.03	0.97
Alon	Catalytic	12.0	0.07	0.11	0.10	0.77	0.12	1.02
San Dimas	Cataract	12.0	0.51	0.59	0.68	2.46	1.68	3.98
Declez	Catawba	12.0	0.64	0.77	0.96	4.70	1.43	5.78
Roadway	Caterpillar	12.0	0.27	0.32	0.40	2.30	0.40	2.52
Bayside	Catfish	12.0	0.73	1.26	1.05	7.30	1.46	8.37
La Veta	Cathy	12.0	0.52	0.97	0.73	5.24	1.09	6.60
Tenaja	Catt	12.0	0.16	0.43	0.21	1.74	0.43	2.96
Tulare	Cattle	12.0	0.42	0.85	0.56	3.87	0.95	5.32
Team	Cavaliers	12.0	0.00	0.00	0.00	0.00	0.01	0.01
Garfield	Cawston	4.16	0.05	0.15	0.06	0.72	0.09	1.07
Bryan	Caymen	12.0	0.31	0.40	0.36	3.53	0.58	4.44
O'neill	Caza	12.0	0.52	0.88	0.81	5.95	0.94	6.54
Delano	Cbs	12.0	0.89	1.10	1.44	7.12	1.85	8.40
Delano	Cecil	4.16	0.17	0.23	0.24	1.08	0.43	1.48
Colorado	Cedar	4.16	0.31	0.49	0.36	1.66	0.67	2.35
Burnt Mill	Cedarglen	12.0	0.16	0.30	0.23	1.73	0.29	1.95
Cedar Pines P.T.	Cedarpines	2.4	0.03	0.04	0.04	0.25	0.05	0.32

Substation	Distribution Circuit	Voltage (kV)	Scenario 1 Coincident Capacity (MW)	Scenario 1 Total Capacity (MW)	Scenario 2 Coincident Capacity (MW)	Scenario 2 Total Capacity (MW)	Scenario 3 Coincident Capacity (MW)	Scenario 3 Total Capacity (MW)
Sun City	Celestial	12.0	0.26	0.58	0.32	2.87	0.62	4.32
Elizabeth Lake	Cello	16.0	0.44	0.66	0.66	4.77	0.87	5.38
Team	Celtics	12.0	1.37	1.62	2.05	8.47	2.85	9.82
Victor	Cement	33.0	0.18	0.39	0.29	2.36	0.29	2.51
San Bernardino	Centaur	12.0	0.60	1.21	0.95	7.09	1.05	7.33
Santiago	Centavo	12.0	1.68	2.99	4.99	17.12	11.80	29.91
Inglewood	Centinela	16.0	0.67	0.88	1.05	5.76	1.22	6.49
Haskell	Centurion	16.0	0.33	0.68	0.34	3.85	0.83	6.34
Lennox	Century	4.16	0.08	0.14	0.10	0.68	0.14	0.87
Temescal P.T.	Ceramic	4.16	0.11	0.17	0.15	0.79	0.31	1.15
Skylark	Cereal	12.0	0.26	0.55	0.36	2.88	0.57	4.04
Daisy	Cero	4.16	0.08	0.14	0.10	0.94	0.13	1.15
Chase	Cerrito	12.0	0.51	0.99	0.68	4.85	1.37	7.46
Mesa	Cerveza	16.0	1.32	1.57	1.96	8.79	2.88	10.60
Stetson	Cessna	12.0	0.53	1.03	0.77	5.37	1.13	6.41
Ganesha	Ceylon	12.0	0.71	0.80	0.98	4.11	2.02	5.83
Moraga	Chablis	12.0	0.60	1.00	0.88	5.81	1.19	6.67
Brighton	Chadron	16.0	0.61	0.83	0.94	6.37	1.24	7.62
Upland	Chaffey	12.0	0.95	1.19	1.27	3.53	3.38	6.41
Chalet P.T.	Chalet	2.4	0.02	0.04	0.03	0.24	0.03	0.28
Zack	Chalfant	12.0	0.08	0.12	0.11	0.47	0.25	0.66
Gisler	Challenger	12.0	0.99	1.31	1.52	6.66	2.00	7.50
Peyton	Champion	12.0	0.32	0.42	0.39	2.49	0.97	4.00
Redlands	Chandler	4.16	0.14	0.17	0.21	0.80	0.29	0.93
Bunker	Chaney	12.0	0.46	1.06	0.71	6.21	0.85	7.18
Wimbledon	Chang	12.0	0.79	1.33	1.27	10.43	1.30	11.58
Rush	Change	16.0	0.99	1.59	1.42	8.91	2.02	10.58
Pico	Channel	12.0	0.07	0.23	0.11	1.46	0.12	1.73
Blythe City	Chanslor	33.0	0.82	1.04	1.33	6.08	1.34	6.10
Arcadia	Chantry	16.0	0.94	1.01	1.32	5.71	2.39	7.47
Santa Barbara	Chapala	4.16	0.12	0.15	0.18	0.76	0.23	0.81
Michillinda	Chapman	4.16	0.03	0.13	0.03	0.55	0.04	0.92
Pauba	Chardonnay	12.0	0.23	0.84	0.31	3.89	0.35	6.05
Slater	Chargers	12.0	0.17	0.48	0.02	4.63	0.15	6.66
Haskell	Chariot	16.0	0.32	1.00	0.34	5.77	0.51	8.48
Longdon	Charity	4.16	0.13	0.13	0.19	0.92	0.33	1.09
Cathedral City	Charlesworth	4.8	0.24	0.41	0.31	1.38	0.77	2.54
Olympic	Charleville	4.16	0.10	0.16	0.14	0.87	0.19	1.01
Alder	Charlie	12.0	0.39	0.88	0.55	4.57	0.90	6.58
Mayberry	Charlton	12.0	0.49	0.89	0.71	4.66	1.13	6.44
Orange	Chartreuse	12.0	0.49	0.97	0.73	5.38	0.96	6.25
Casa Diablo	Chateau	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Tennessee	Chattanooga	12.0	0.37	0.82	0.55	4.14	0.77	5.31
Baker	Chavez	12.0	0.10	0.17	0.12	0.49	0.22	0.75
Pechanga	Chawa	12.0	0.52	0.99	0.77	5.61	1.03	6.87
Stadler	Cheerleader	12.0	0.37	0.70	0.52	3.43	0.80	4.31
Tulare	Cheese	12.0	1.80	3.25	5.35	18.42	12.81	32.00
Lampson	Cheetah	12.0	0.86	1.38	1.22	7.68	1.80	9.01
Walnut	Chella	12.0	0.57	0.59	0.73	3.47	1.74	5.73
Colorado	Chelsea	4.16	0.01	0.07	-0.06	0.88	-0.04	1.51
Sepulveda	Chemical	16.0	0.36	0.48	0.58	3.37	0.59	3.58
Topanga	Cheney	4.16	0.02	0.09	0.01	0.55	0.01	0.93
MacArthur	Chenualt	12.0	0.61	1.24	0.95	6.79	1.09	7.11
Shawnee	Cherokee	12.0	1.00	1.09	1.38	7.59	2.41	10.25
State Street	Chestnut	12.0	0.07	0.14	0.11	0.81	0.11	0.82
Culver	Cheviot	4.16	0.18	0.27	0.25	1.65	0.38	1.97
Shuttle	Chewbacca	12.0	0.49	0.86	0.74	4.77	0.92	6.06
Shawnee	Cheyenne	12.0	0.30	0.35	0.42	1.70	0.88	2.49
Tamarisk	Chia	12.0	0.91	1.20	1.25	4.87	2.80	7.72
Belvedere	Chicago	4.16	0.12	0.17	0.17	1.20	0.20	1.34
Rolling Hills	Chico	16.0	0.37	0.72	0.39	4.33	0.63	5.38
Ely	Chile	12.0	1.11	1.52	1.74	10.62	2.16	12.36
Chillon P.T.	Chillon	2.4	0.03	0.08	0.05	0.48	0.05	0.56
Jefferson	Chimay	12.0	0.35	0.60	0.54	4.70	0.61	5.44
Ganesha	Chime	12.0	0.51	0.62	0.72	3.45	1.18	4.47
Modena	China	12.0	0.50	0.83	0.67	5.32	0.99	6.63
Lunar	Chinapeak	12.0	0.04	0.08	0.06	0.55	0.07	0.69
China Ranch P.T.	Chinaranch	2.4	0.00	0.00	0.00	0.02	0.00	0.02
Liberty	Chinowth	12.0	0.32	0.91	0.40	4.02	0.80	6.25

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Gilbert	Chipper	12.0	0.71	1.15	1.02	8.26	1.43	10.27
Shawnee	Chippewa	12.0	0.71	0.77	1.03	4.73	1.60	5.89
Shawnee	Choctaw	12.0	1.37	2.01	3.84	12.12	8.67	20.71
Apple Valley	Choiceanna	12.0	0.41	0.61	0.58	3.76	0.79	4.78
Mescalero P.T.	Cholla	4.8	0.05	0.11	0.08	0.48	0.12	0.69
Chollita P.T.	Chollita	12.0	0.17	0.27	0.24	1.21	0.36	1.62
Chovy P.T.	Chovy	4.16	-0.01	0.01	-0.02	-0.04	0.02	0.20
Watson	Chris	12.0	0.52	0.75	0.76	5.78	0.85	6.72
La Veta	Christine	12.0	0.48	0.72	0.66	3.87	1.28	5.26
Lark Ellen	Christy	12.0	0.39	0.50	0.60	4.07	0.69	4.35
Limestone	Chrome	12.0	0.18	0.53	0.11	3.66	0.27	5.65
Laguna Bell	Chrysler	16.0	0.66	0.94	1.05	5.66	1.18	5.81
Eagle Mountain	Chuckawalla	12.0	0.06	0.10	0.09	0.54	0.10	0.63
Ramona	Chucker	4.16	0.11	0.13	0.15	0.93	0.24	1.13
Ivyglen	Chuckwagon	12.0	0.31	0.49	0.62	4.38	1.02	6.62
Malibu	Chumash	16.0	0.65	0.85	1.04	4.75	1.15	4.93
Gallatin	Church	12.0	0.51	0.62	0.75	3.25	1.25	4.08
MacArthur	Churchill	12.0	0.32	0.70	0.51	4.07	0.53	4.16
Verdant	Cibola	12.0	0.04	0.07	0.06	0.33	0.07	0.44
Santa Barbara	Cienigitas	16.0	0.62	0.73	0.95	3.94	1.22	4.30
Inglewood	Cimarron	16.0	0.71	1.16	0.98	5.83	1.33	7.06
Coso	Cinder	12.0	0.10	0.19	0.16	1.05	0.17	1.09
Oak Springs P.T.	Circle	12.0	0.04	0.04	0.06	0.27	0.13	0.36
San Miguel	Cisco	16.0	1.01	1.30	1.55	6.60	2.01	7.14
Aqueduct	Cistern	12.0	0.54	0.80	0.79	3.85	1.29	5.23
Signal Hill	Citizens	12.0	0.54	0.67	0.83	3.38	1.11	3.69
Declez	Citrow	12.0	0.83	1.04	1.29	6.97	1.68	7.80
Highland	Citycreek	12.0	0.39	0.63	0.65	4.36	0.92	5.65
Banning	Cityofbanning#1	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Banning	Cityofbanning#2	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Banning	Cityofbanning#3	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Anaverde	Cityranch	12.0	0.72	0.91	1.17	5.25	1.55	6.03
Wave	Civic	4.16	0.07	0.17	0.09	0.93	0.12	1.18
Twentynine Palms	Civiccenter	4.8	0.15	0.18	0.25	1.16	0.35	1.54
Cypress	Clair	12.0	0.72	0.88	1.15	6.01	1.25	6.48
Porterville	Clampett	12.0	0.34	0.85	0.51	3.92	0.59	5.60
Oak Grove	Clancy	12.0	0.59	0.48	0.88	4.42	1.17	4.76
Cudahy	Clara	4.16	0.06	0.12	0.08	0.61	0.11	0.81
Elizabeth Lake	Clarinet	16.0	0.28	0.83	0.33	4.52	0.46	6.29
Marion	Claudia	12.0	0.20	0.49	0.18	3.56	0.23	5.13
Wave	Clay	12.0	0.53	1.06	0.74	6.16	0.91	7.00
Peerless	Claymine	12.0	0.01	0.02	0.01	0.07	0.03	0.09
Rosemead	Clayton	16.0	0.60	0.88	0.85	5.89	1.25	7.22
Washington	Cleat	12.0	0.23	0.40	0.32	2.20	0.41	2.58
Naomi	Clemont	4.16	0.12	0.22	0.19	1.14	0.21	1.39
Somis	Clemson	16.0	0.60	0.66	0.88	4.31	1.34	5.25
Ditmar	Cleo	4.16	-0.02	0.20	-0.12	0.87	-0.12	2.25
Cornuta	Clerk	12.0	0.61	0.86	0.96	4.89	1.23	5.26
O'neill	Cleveland	12.0	0.23	1.04	0.23	5.00	0.29	8.07
Costa Mesa	Cliff	4.16	0.05	0.17	0.03	0.95	0.05	1.61
Stewart	Clifford	12.0	0.97	1.22	1.47	6.73	2.11	7.87
Redondo	Clifton	4.16	0.03	0.14	0.01	1.03	0.02	1.48
Porterville	Cline	4.16	0.13	0.20	0.20	1.03	0.24	1.26
Timoteo	Clinic	12.0	0.16	0.30	0.23	1.61	0.31	1.82
Nelson	Clinton	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Lunada	Clipper	4.16	0.02	0.01	0.02	0.18	0.08	0.32
Poplar	Cloer	12.0	0.38	0.58	0.55	3.75	0.71	4.87
Moreno	Clove	12.0	0.47	0.88	0.65	3.74	1.23	5.40
Barre	Clover	12.0	0.38	0.83	0.46	5.39	0.57	7.07
Ocean Park	Cloverfield	4.16	0.04	0.09	-0.02	0.95	0.04	1.36
Temple	Cloverly	4.16	0.19	0.24	0.24	1.12	0.49	1.62
Santa Rosa	Clubhouse	12.0	0.91	1.51	1.47	8.57	1.49	8.83
Cardiff	Cluboaks	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Narod	Clutch	12.0	0.48	0.80	0.67	3.91	1.31	5.53
Auld	Clydesdale	12.0	0.41	0.93	0.60	5.27	0.83	6.81
Placentia	Coach	12.0	0.54	0.90	0.72	4.23	1.40	6.13
Garnet	Coachella	33.0	0.01	0.01	0.01	0.08	0.01	0.10
Limestone	Coal	12.0	0.35	0.52	0.48	4.29	0.63	4.92
Victor	Coalinga	12.0	0.54	0.66	0.79	3.78	1.31	4.89

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Crown	Coastal	12.0	0.34	0.91	0.39	5.34	0.49	7.40
Camden	Cobalt	12.0	0.64	1.09	0.88	7.31	1.09	8.54
North Oaks	Cobra	16.0	0.26	0.46	0.37	2.34	0.54	2.79
Bryan	Cocamo	12.0	0.35	0.71	0.50	3.97	0.69	4.89
Apple Valley	Cochise	12.0	0.39	0.46	0.56	2.22	0.99	2.79
Chestnut	Coco	12.0	1.11	1.84	1.54	8.95	2.39	10.84
Pierpont	Code	4.16	0.04	0.09	0.05	0.80	0.06	0.92
Walteria	Codona	4.16	0.05	0.20	0.05	0.93	0.06	1.54
Pioneer	Cody	12.0	1.20	1.51	1.91	9.92	2.15	10.81
Bartolo	Coffee	4.16	0.07	0.09	0.09	0.65	0.14	0.76
Chiquita	Cognac	12.0	0.06	0.08	0.00	1.67	0.03	2.25
Amador	Cogswell	4.16	0.11	0.16	0.16	1.04	0.24	1.24
Gaviota	Cojo	16.0	0.02	0.04	0.02	0.15	0.04	0.19
Arro	Cola	4.16	0.02	0.02	0.01	0.02	0.04	0.06
Upland	Colburn	4.16	0.12	0.18	0.16	0.98	0.31	1.36
Coldbrook P.T.	Coldbrook	4.16	0.03	0.07	0.05	0.34	0.07	0.42
Beverly	Coldwater	4.16	0.16	0.24	0.22	1.01	0.49	1.60
Michillinda	Cole	4.16	0.10	0.19	0.13	1.11	0.23	1.54
La Habra	Colfax	12.0	0.59	0.82	0.83	4.09	1.54	5.14
San Antonio	Colgate	12.0	0.33	0.64	0.45	3.18	0.70	4.11
Stadium	Coliseum	12.0	0.06	0.13	0.09	0.77	0.10	0.93
Randall	Colleen	12.0	0.51	0.98	0.76	5.20	1.01	6.02
Upland	Collegepark	4.16	0.11	0.15	0.22	1.07	0.42	1.54
Moulton	Collie	12.0	0.39	0.71	0.56	4.21	0.76	5.06
Elsinore	Collier	12.0	0.45	1.12	0.63	6.49	0.76	8.29
Moorpark	Collins	16.0	1.33	1.46	1.96	8.98	2.95	10.77
Colonia	Colonia66/16-09	16.0	0.00	0.00	0.00	0.00	0.00	0.00
East Barstow	Color	4.16	0.10	0.17	0.12	0.62	0.21	0.91
Auld	Colt	12.0	0.31	0.59	0.47	4.89	0.52	6.08
Amador	Columbia	4.16	0.15	0.28	0.19	1.30	0.30	1.69
Bullis	Colyer	16.0	1.31	1.66	1.97	8.67	2.83	10.20
Shawnee	Comanche	12.0	0.71	0.63	0.93	5.25	1.71	7.34
Eisenhower	Combat	12.0	0.83	1.02	1.21	5.40	2.04	7.04
Chino	Comet	12.0	0.05	0.13	0.01	1.41	0.05	2.07
Monrovia	Commercial	4.16	0.13	0.17	0.18	0.93	0.36	1.23
Alhambra	Commonwealth	4.16	0.16	0.35	0.21	1.32	0.34	1.87
Community P.T.	Community	2.4	0.00	0.00	0.00	0.02	0.00	0.02
Perry	Como	4.16	0.03	0.06	0.00	0.80	0.02	0.98
Fullerton	Complex	12.0	0.47	0.81	0.58	3.50	1.08	5.00
Sepulveda	Computer	16.0	0.77	1.12	1.24	6.64	1.30	7.13
Lucas	Conant	12.0	0.47	0.96	0.63	6.08	0.78	6.82
Gaviota	Concepcion	16.0	0.07	0.11	0.09	0.43	0.21	0.61
Monrovia	Concord	4.16	0.06	0.13	0.08	0.69	0.16	1.08
Vail	Concourse	16.0	0.53	0.68	0.81	4.03	1.22	4.86
Dalton	Concrete	12.0	0.57	0.74	0.91	5.49	1.06	6.43
Malibu	Conejo	16.0	0.58	1.15	0.83	6.28	1.31	8.07
Ivyglen	Conestoga	12.0	1.11	1.41	1.47	6.31	3.91	10.30
Forest Home	Conference	2.4	0.00	0.00	0.00	0.02	0.01	0.02
Francis	Congo	12.0	0.35	0.73	0.46	3.74	0.79	5.34
Cornuta	Congress	12.0	0.13	0.16	0.19	0.88	0.28	1.03
Oak Park	Conifer	16.0	0.91	0.93	1.08	4.69	2.82	8.14
Yucaipa	Conine	12.0	0.34	0.56	0.50	3.25	0.78	4.10
Corum	Conley	12.0	0.27	0.35	0.43	2.58	0.50	2.71
Carolina	Connecticut	12.0	0.60	1.14	0.91	6.54	1.16	7.41
Wimbledon	Conners	12.0	0.60	0.72	0.97	6.64	1.01	7.73
Bain	Conning	12.0	0.62	1.33	0.87	8.29	1.16	10.06
Viejo	Consejo	12.0	2.42	3.40	7.59	19.37	18.58	35.39
Haskell	Constantine	16.0	0.07	0.84	-0.07	4.10	-0.06	7.64
Holgate	Conte	12.0	0.17	0.27	0.22	1.02	0.35	1.44
Sepulveda	Continent	16.0	0.75	1.05	1.22	7.07	1.24	7.45
Naomi	Converse	4.16	0.06	0.11	0.08	0.69	0.10	0.78
Fruitland	Convex	16.0	0.00	0.01	0.01	0.03	0.01	0.03
Industry	Conveyor	12.0	0.68	0.83	1.03	5.09	1.47	6.10
Lundy	Conway	16.0	0.01	0.02	0.01	0.10	0.02	0.11
Stadium	Cony	12.0	0.60	0.94	0.82	6.37	1.23	7.96
Visalia	Conyer	4.16	0.05	0.09	0.07	0.37	0.13	0.50
Chiquita	Cooler	12.0	0.17	0.39	0.19	2.47	0.26	3.39
Colton	Cooley	12.0	0.38	0.70	0.55	3.93	0.86	5.30
Tipton	Cooper	12.0	0.47	0.64	0.71	4.97	0.97	6.53

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Bandini	Copper	16.0	0.55	0.64	0.88	5.67	0.93	6.63
North Oaks	Copperhead	16.0	0.35	0.61	0.51	3.56	0.66	3.85
Moneta	Copra	4.16	0.06	0.08	0.08	0.51	0.10	0.61
Copy P.T.	Copy	4.16	0.01	0.02	0.01	0.06	0.03	0.09
Bassett	Corak	12.0	0.40	0.52	0.60	2.85	0.85	3.37
Topaz	Coral	4.16	0.03	0.03	0.03	0.28	0.04	0.36
Bayside	Corbina	12.0	0.56	0.98	0.81	5.55	1.16	6.53
Eric	Corby	12.0	0.77	1.00	1.17	5.94	1.51	6.79
Beverly	Cord	4.16	0.09	0.12	0.14	0.64	0.16	0.67
Hanford	Cordial	12.0	0.56	1.00	0.76	4.60	1.23	6.64
Santiago	Cordoba	12.0	0.24	0.53	0.38	3.13	0.41	3.37
Archline	Cordon	12.0	0.51	0.89	0.75	5.22	1.15	6.73
Granada	Cordova	4.16	0.10	0.25	0.12	0.78	0.29	1.54
Tenaja	Corinth	12.0	0.38	0.80	0.55	4.95	0.73	6.04
Lakeside P.T.	Cornell	4.16	0.05	0.03	0.06	0.27	0.18	0.45
Lynwood	Cornish	4.16	0.12	0.16	0.18	1.24	0.18	1.45
Chestnut	Cornnut	12.0	0.37	0.69	0.58	4.48	0.64	4.89
Narrows	Cornwall	12.0	0.77	1.30	1.13	8.88	1.43	10.55
Mesa	Coronado	16.0	0.61	1.27	0.96	7.74	1.06	8.54
Jefferson	Coronita	12.0	0.43	0.59	0.56	3.63	1.13	5.16
Bunker	Corporal	12.0	0.50	0.85	0.73	4.94	1.10	6.25
Belmont	Corral	4.16	0.09	0.14	0.10	1.12	0.14	1.41
Corrigan P.T.	Corrigan	2.4	0.08	0.08	0.10	0.46	0.27	0.72
Los Cerritos	Corrine	4.16	0.14	0.15	0.18	0.88	0.41	1.23
Stetson	Corsair	12.0	0.35	0.96	0.49	5.18	0.60	6.94
Gonzales	Corsica	16.0	1.76	2.19	2.54	12.18	3.81	14.36
Victorville	Corta	4.16	0.04	0.07	0.05	0.34	0.07	0.44
Morro	Cortese	12.0	0.11	0.17	0.14	0.78	0.25	1.00
Narrows	Corvette	12.0	0.05	0.10	0.07	0.63	0.08	0.74
Beverly	Cory	16.0	0.60	1.34	0.88	6.66	1.25	8.37
Santa Rosa	Costello	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Larder	Cota	4.16	0.25	0.48	0.38	2.98	0.40	3.13
Cottage Grove	Cottagegrove	2.4	0.02	0.04	0.04	0.29	0.04	0.35
Poplar	Cotton	12.0	0.26	0.57	0.38	3.33	0.47	4.32
North Oaks	Cottonmouth	16.0	0.48	0.84	0.59	4.74	1.05	6.47
Lampson	Cougar	12.0	0.26	0.52	0.43	3.21	0.44	3.28
Coulter P.T.	Coulter	2.4	0.00	0.00	0.00	0.00	0.00	0.00
Beverly	Countryclub	4.16	0.06	0.08	0.10	0.42	0.13	0.46
Walnut	Countrywood	12.0	1.01	1.25	1.53	6.30	2.13	8.82
Counts P.T.	Counts	2.4	0.00	0.01	0.00	0.02	0.01	0.03
Watson	County	12.0	0.28	0.38	0.45	3.41	0.46	3.98
Layfair	Countyfair1	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Layfair	Countyfair5	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Railroad	Coupler	12.0	0.42	0.45	0.50	3.26	1.12	5.36
Placentia	Course	12.0	0.18	0.26	0.25	1.62	0.35	1.81
Palmdale	Courson	12.0	0.43	0.62	0.60	3.27	0.96	4.32
Locust	Court	4.16	0.08	0.15	0.12	0.81	0.15	0.91
Marine	Courtland	16.0	0.30	0.31	0.46	1.89	0.55	2.02
Cove P.T.	Cove	12.0	0.11	0.19	0.17	1.05	0.22	1.32
Thousand Oaks	Coventry	16.0	1.44	1.93	2.15	9.52	3.14	11.39
Marymount	Coveview	16.0	0.14	0.46	0.04	2.86	0.12	4.89
Railroad	Cowcatcher	12.0	0.85	1.05	1.28	5.62	1.83	7.56
Mt. Vernon	Cowen	4.16	0.07	0.15	0.10	0.87	0.11	1.03
State Street	Cowles	12.0	0.18	0.36	0.23	1.28	0.47	1.85
Bowl	Cox	12.0	0.58	0.76	0.88	3.76	1.26	4.22
Somerset	Coyote	12.0	0.30	0.39	0.46	2.28	0.62	2.67
Arrowhead	Crab	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Saugus	Crabtree	16.0	1.12	1.36	1.65	7.74	2.68	9.63
Homart	Craftsman	12.0	0.10	0.25	0.16	1.38	0.18	1.45
Highland	Cram	12.0	0.37	0.78	0.50	3.77	0.87	5.53
Yukon	Cranbrook	4.16	0.09	0.16	0.12	0.98	0.15	1.13
Compton	Crane	4.16	0.17	0.26	0.26	1.62	0.29	1.86
Crawford P.T.	Crawford	2.4	0.00	0.02	0.01	0.08	0.01	0.12
Cudahy	Creamery	16.0	0.52	0.62	0.75	3.04	1.17	3.80
Oak Grove	Cree	12.0	0.29	0.52	0.45	3.38	0.56	3.51
Archibald	Creekside	12.0	0.37	0.47	0.50	3.23	0.87	4.21
Moneta	Crenshaw	4.16	0.09	0.17	0.13	0.97	0.15	1.21
Tamarisk	Creosote	12.0	0.71	1.17	1.00	4.59	2.04	7.36
Fairfax	Crescent	4.16	0.22	0.27	0.34	1.46	0.40	1.55

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Gould	Crescenta	16.0	0.66	0.84	0.77	4.90	2.17	8.40
Alhambra	Cresta	16.0	0.52	1.10	0.79	6.59	0.90	7.28
Oak Park	Cresthaven	16.0	0.91	1.42	1.14	5.88	2.96	9.99
Huston	Crestline	2.4	0.05	0.12	0.08	0.62	0.09	0.77
Crestwind U.G.S.	Crestwind	4.16	0.03	0.11	0.02	0.62	0.03	1.02
Liberty	Crestwood	12.0	0.43	1.00	0.59	4.57	1.22	6.50
Cortez	Crevolin	12.0	0.58	0.67	0.80	3.58	1.64	5.06
Johanna	Cribbage	12.0	0.48	0.76	0.75	5.61	0.84	6.28
Sunny Dunes	Crocker	4.16	0.09	0.16	0.14	0.74	0.19	0.99
Graham	Crockett	4.16	0.17	0.35	0.25	1.80	0.27	2.32
Yucaipa	Croft	12.0	0.51	0.78	0.72	4.49	1.25	5.95
Irvine	Cromwell	12.0	0.30	0.73	0.44	4.90	0.46	5.49
Hamilton	Cronin	12.0	0.33	0.72	0.21	5.42	0.45	7.40
Fair Oaks	Crosby	4.16	0.12	0.09	0.13	0.87	0.34	1.31
Newhall	Cross	16.0	0.43	0.99	0.55	5.04	0.97	7.23
Eisenhower	Crossley	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Camarillo	Crosson	16.0	1.21	1.50	1.63	10.10	2.36	12.80
Cabrillo	Crosstown	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Lancaster	Crowder	12.0	0.57	0.92	0.78	4.51	1.06	5.72
Casa Diablo	Crowley	12.0	0.07	0.13	0.08	0.48	0.14	0.62
Pechanga	Crownhill	12.0	0.11	0.55	0.10	2.37	0.19	4.27
Atwood	Crowther	12.0	0.33	0.58	0.47	3.77	0.64	4.62
Malibu	Crumner	16.0	0.86	1.44	1.20	7.49	1.98	9.50
Crump P.T.	Crump	12.0	0.04	0.08	0.04	0.39	0.07	0.54
Downs	Crumville	12.0	0.86	1.15	1.30	5.76	1.80	6.60
Center	Crusade	12.0	0.88	1.10	1.36	6.91	1.63	7.63
Moraga	Cruz	12.0	0.53	1.06	0.73	5.57	1.12	7.28
Wave	Crystal	4.16	0.01	0.06	0.01	0.33	0.01	0.52
Ely	Cuba	12.0	0.73	0.98	1.14	7.45	1.35	8.82
Edinger	Cubbon	4.16	0.08	0.11	0.11	0.96	0.11	1.06
Upland	Cubic	12.0	0.51	0.81	0.78	5.40	1.00	6.40
Cummings	Cuddeback	12.0	0.43	0.54	0.56	3.15	0.98	4.31
Milliken	Cuervo	12.0	0.57	0.70	0.90	4.51	0.99	4.88
Cabrillo	Culverdale	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Proctor	Cupid	12.0	1.63	2.37	4.08	16.38	8.53	25.92
Corona	Cupples	33.0	0.17	0.45	0.27	3.57	0.28	4.03
Ontario	Curran	4.16	0.14	0.23	0.20	1.15	0.29	1.41
Goshen	Curtis	12.0	0.66	0.90	1.01	6.93	1.27	8.95
Cottonwood	Cushenbury	33.0	0.00	0.06	0.00	1.49	0.00	3.03
Latigo	Cuthbert	16.0	0.42	1.10	0.48	5.97	0.56	9.11
Visalia	Cutler	12.0	0.56	0.85	0.74	3.93	1.86	5.70
Cudahy	Cyanide	16.0	1.15	1.51	1.75	8.53	2.45	9.98
Yorba Linda	Cyclone	12.0	0.27	1.00	0.31	4.64	0.41	6.85
Proctor	Cyclops	12.0	0.77	1.02	1.22	8.14	1.42	10.03
Ditmar	Cylinder	16.0	0.35	0.86	0.44	4.91	0.57	6.01
Niguel	Cymbal	12.0	0.28	0.40	0.39	2.84	0.50	3.07
Beverly	Cynthia	4.16	0.12	0.16	0.17	0.73	0.24	0.88
Colorado	Cyrus	16.0	0.33	0.85	0.52	4.94	0.56	5.14
Moulton	Dachshund	12.0	0.62	1.11	0.88	5.61	1.23	6.43
Daeley P.T.	Daeley	4.16	0.02	-0.01	0.02	0.15	0.04	0.19
Barre	Daffodil	12.0	0.45	0.87	0.65	4.31	1.04	5.48
Hathaway	Daggett	4.16	0.07	0.11	0.09	0.85	0.11	0.99
Rolling Hills	Dahlia	4.16	0.04	0.08	0.03	0.68	0.05	0.85
Hinkley	Dairy	12.0	0.13	0.24	0.17	0.80	0.31	1.22
Chino	Dairyman	12.0	0.07	0.12	0.09	0.42	0.18	0.64
Carolina	Dakota	12.0	0.70	1.24	1.06	7.15	1.34	7.91
Dalba P.T.	Dalba	2.4	0.04	0.08	0.06	0.44	0.06	0.50
Carson	Dalberg	16.0	0.37	0.48	0.60	4.12	0.63	4.86
Brighton	Daleside	16.0	0.54	0.91	0.78	5.30	0.99	6.56
Trask	Dallas	12.0	0.88	0.97	1.31	5.97	1.82	6.82
Firehouse	Dalmatian	12.0	0.79	1.29	1.20	7.55	1.55	8.52
Dalton	Dameral	12.0	0.99	1.56	1.57	12.86	1.72	15.06
Jefferson	Dana	12.0	0.36	0.45	0.50	3.44	0.67	4.02
Camino	Danby	16.0	0.04	0.07	0.06	0.31	0.08	0.37
San Gabriel	Danes	4.16	0.04	0.13	0.04	0.76	0.06	1.04
Etiwanda	Dangerfield	12.0	0.39	0.59	0.49	2.86	1.27	4.85
Beverly	Daniels	16.0	0.41	0.91	0.64	5.07	0.73	5.27
Archibald	Danish	12.0	0.33	0.57	0.38	1.52	1.29	3.62
Rio Hondo	Danube	12.0	0.84	1.00	1.28	6.32	1.77	6.91

Substation	Distribution Circuit	Voltage (kV)	Scenario 1 Coincident Capacity (MW)	Scenario 1 Total Capacity (MW)	Scenario 2 Coincident Capacity (MW)	Scenario 2 Total Capacity (MW)	Scenario 3 Coincident Capacity (MW)	Scenario 3 Total Capacity (MW)
Morningside	Darby	4.16	0.12	0.20	0.16	1.22	0.19	1.50
Amador	Daroca	16.0	0.51	0.89	0.74	4.71	1.02	5.50
La Mirada	Dart	12.0	0.65	0.78	1.01	4.75	1.17	4.95
Mayberry	Dartmouth	12.0	0.55	1.08	0.84	6.29	1.11	7.51
Ellis	Darwin	12.0	0.74	1.23	1.13	7.11	1.36	7.73
Lucas	Dashwood	4.16	0.09	0.07	0.11	0.63	0.26	0.84
Olive Lake	Date	12.0	0.20	0.31	0.29	1.26	0.52	1.81
Farrell	Datepalm	12.0	0.53	0.67	1.02	4.96	1.58	6.51
Solemint	Davenport	16.0	0.43	0.98	0.54	4.14	1.08	6.59
Vail	Davie	16.0	2.48	3.83	7.67	19.42	18.85	39.24
Beverly	Dayton	4.16	0.16	0.21	0.26	1.09	0.32	1.17
Soquel	Deacano	12.0	0.75	1.28	1.11	9.23	1.20	10.47
Valley	Deacon	12.0	0.71	1.44	1.10	9.08	1.27	10.60
Phelan	Dealer	12.0	0.74	1.08	1.11	6.00	1.59	7.64
Lark Ellen	Deanna	12.0	0.72	0.91	1.05	4.85	1.61	5.90
Redlands	Dearborn	12.0	0.71	0.89	1.07	4.73	1.64	5.57
Santa Monica	Deauville	4.16	0.03	0.06	0.04	0.29	0.06	0.31
Felton	Deborah	16.0	0.50	0.67	0.69	3.93	0.85	4.59
Santa Monica	Debug	16.0	0.91	1.82	1.42	10.19	1.62	10.57
Oak Grove	Decamp	12.0	0.52	0.67	0.95	5.12	1.39	7.64
Clark	Decca	4.16	0.03	0.02	-0.03	0.88	-0.02	1.28
Passons	Decosta	12.0	0.45	0.74	0.67	5.51	0.82	6.47
Center	Decoy	12.0	0.23	0.30	0.31	1.78	0.57	2.31
South Gate	Deeble	4.16	0.08	0.11	0.12	0.74	0.13	0.80
Nelson	Deegan	12.0	0.26	0.36	0.38	2.17	0.73	2.75
Indian Wells	Deepcanyon	12.0	0.48	0.59	0.90	3.78	1.26	4.39
Apple Valley	Deepcreek	12.0	0.72	0.98	1.17	5.67	1.40	6.08
Terra Bella	Deer	12.0	0.52	0.77	0.72	3.54	1.11	4.49
Ravendale	Deerfield	16.0	0.41	0.91	0.53	5.63	0.65	7.15
Downs	Deeter	12.0	0.52	0.72	0.71	3.84	1.25	5.18
Deigaard P.T.	Deigaard	4.16	0.01	0.03	0.01	0.18	0.03	0.23
Amalia	Delarro	4.16	0.08	0.12	0.12	0.75	0.17	0.86
Colorado	Delaware	16.0	0.59	1.12	0.89	6.22	1.12	6.74
Peyton	Delcarbon	12.0	0.24	0.37	0.61	3.22	1.29	4.97
La Palma	Delco	12.0	0.49	0.87	0.72	4.63	1.01	5.25
Bradbury	Delford	16.0	0.67	0.85	1.03	4.51	1.34	5.07
Fairview	Delhi	12.0	0.75	1.59	1.16	9.34	1.34	10.12
Moneta	Delid	4.16	0.09	0.09	0.08	1.12	0.12	1.33
Second Avenue	Deljuan	12.0	0.08	0.10	0.15	0.82	0.21	1.17
San Gabriel	Delmar	4.16	0.09	0.12	0.14	0.95	0.15	1.12
Apple Valley	Deloro	12.0	0.97	1.22	1.40	5.90	2.39	7.49
Playa	Delrey	4.16	0.09	0.12	0.13	0.84	0.15	1.07
Venida	Delta	12.0	0.66	1.21	1.03	9.26	1.12	10.39
Deluz P.T.	Deluz	12.0	0.05	0.17	0.07	0.66	0.09	1.06
Oak Grove	Demaree	12.0	0.67	1.35	0.94	6.57	1.76	8.02
Corona	Demari	4.16	0.09	0.12	0.15	0.74	0.27	0.98
Kagle Canyon P.T.	Demille	4.16	0.04	0.06	0.07	0.44	0.10	0.56
Oxnard	Dempsey	4.16	0.23	0.34	0.31	1.70	0.44	2.06
Lark Ellen	Denise	12.0	0.50	0.64	0.78	3.73	0.89	3.89
Howard	Denker	4.16	0.17	0.25	0.26	1.53	0.29	1.67
Little Rock	Dennis	12.0	0.00	0.00	0.00	0.00	0.01	0.01
Timoteo	Dental	12.0	0.42	0.93	0.57	4.86	0.89	6.46
Cameron	Denver	12.0	0.30	0.77	0.47	4.57	0.51	4.83
La Habra	Deodara	12.0	0.79	0.98	1.24	6.73	1.51	7.04
Colton	Derby	12.0	0.09	0.20	0.13	1.09	0.19	1.46
Signal Hill	Derrick	4.16	0.01	-0.01	-0.04	0.66	-0.03	0.90
Lancaster	Desert	4.16	0.05	0.06	0.07	0.31	0.11	0.38
Eagle Mountain	Desertcenter	12.0	0.08	0.11	0.10	0.52	0.16	0.66
Garnet	Desertcrest	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Pico	Desmond	12.0	0.05	0.08	0.08	0.54	0.08	0.63
Cady	Desolate	12.0	0.17	0.35	0.24	1.92	0.31	2.86
Narod	Dessau	12.0	0.84	1.02	1.25	5.47	1.96	6.59
Norco	Detroit	4.16	0.02	0.02	0.02	0.10	0.06	0.15
Gallatin	Deuce	12.0	0.33	0.64	0.44	3.65	0.58	4.31
Arroyo	Devilsgate	16.0	0.63	1.18	0.95	7.52	1.12	8.96
Thousand Oaks	Devine	16.0	0.79	0.96	1.12	5.14	1.82	6.42
Bovine	Devon	12.0	0.67	0.81	0.97	4.52	1.47	5.55
Newhall	Dewitt	16.0	0.28	0.86	0.37	4.78	0.45	6.43
Ganesha	Diabar	12.0	0.00	0.00	0.00	0.00	0.00	0.00

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
San Miguel	Diablo	16.0	1.37	1.89	1.90	11.35	2.70	12.98
Liberty	Diamante	12.0	0.39	1.10	0.59	5.73	0.81	7.09
Arcadia	Diamond	4.16	0.14	0.22	0.19	1.36	0.28	1.67
North Oaks	Diamondback	16.0	0.32	0.77	0.43	3.64	0.77	5.41
Marion	Diana	12.0	0.47	0.82	0.69	4.91	0.92	5.62
Moraga	Diaz	12.0	0.68	1.29	1.03	7.24	1.29	7.95
Phelan	Dice	33.0	0.01	0.02	0.02	0.16	0.02	0.16
Randolph	Dickerson	16.0	0.47	0.60	0.75	4.49	0.94	5.51
Industry	Die	12.0	0.49	0.51	0.75	4.10	0.87	4.53
Randall	Digby	12.0	0.50	0.74	0.67	4.13	1.34	5.85
Moreno	Dill	12.0	0.17	0.21	0.26	2.01	0.28	2.21
Garnet	Dillon	12.0	0.04	0.08	0.06	0.45	0.07	0.48
Santiago	Dime	12.0	0.44	0.69	0.52	5.21	0.83	6.54
Railroad	Diner	12.0	0.57	0.84	0.84	4.89	1.22	6.73
Bolsa	Dingy	12.0	0.92	1.04	1.38	7.01	1.98	8.26
Dinkey Creek P.T.	Dinkeycreek	4.16	0.01	0.01	0.01	0.06	0.02	0.08
Chase	Diplomat	12.0	0.31	0.54	0.44	3.88	0.61	4.99
Goldtown	Discovery	12.0	0.12	0.32	0.16	1.45	0.27	1.98
Gonzales	Ditch	16.0	1.04	2.17	1.49	14.36	1.79	16.04
Belvedere	Ditman	4.16	0.13	0.23	0.19	1.40	0.22	1.55
La Habra	Ditwood	12.0	0.16	0.46	0.26	2.70	0.26	2.71
Rosamond	Division	12.0	0.76	1.07	1.05	4.82	1.74	6.64
Gilbert	Divot	12.0	0.17	0.53	0.15	2.44	0.31	4.20
Villa Park	Dixie	12.0	0.57	1.24	0.78	6.27	1.05	7.25
Declez	Dixon	12.0	1.08	1.40	1.67	8.55	2.11	10.50
San Antonio	Doane	12.0	0.50	0.62	0.75	3.05	0.98	3.39
San Gabriel	Dobbins	4.16	0.08	0.25	0.07	1.07	0.14	1.73
Moulton	Dober	12.0	0.44	0.90	0.64	5.06	0.85	6.06
Cottonwood	Doble	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Timoteo	Doctors	12.0	0.48	0.98	0.72	5.35	0.93	6.32
Cedarwood	Doctrine	4.16	0.04	0.07	0.06	0.48	0.07	0.57
Laguna Bell	Dodge	16.0	0.88	1.09	1.34	6.35	1.82	6.88
La Mirada	Doe	12.0	0.68	0.83	0.99	4.69	1.49	5.68
Santa Fe Springs	Doerner	12.0	0.60	0.74	0.95	4.63	1.11	4.81
Calcity 'B'	Dogbane	12.0	0.20	0.41	0.30	2.14	0.43	2.80
Torrance	Dogwood	16.0	1.12	2.16	1.70	12.47	1.94	13.93
Pioneer	Dohn	4.16	0.11	0.14	0.16	1.06	0.25	1.28
Santa Fe Springs	Dolan	12.0	0.35	0.62	0.52	3.44	0.69	3.80
Alhambra	Dolgeville	4.16	0.08	0.13	0.11	0.73	0.16	0.87
Oldfield	Dollar	4.16	0.10	0.23	0.12	1.17	0.15	1.71
Dolores P.T.	Dolores	4.16	-0.01	0.02	-0.05	0.32	-0.05	0.58
Dolphin P.T.	Dolphin	4.16	0.02	0.03	0.03	0.14	0.05	0.16
Domeland P.T.	Domeland	12.0	0.02	0.03	0.03	0.26	0.04	0.26
Colton	Domic	12.0	0.28	0.45	0.42	3.03	0.53	3.57
La Fresa	Dominguez	16.0	1.05	1.28	1.60	6.98	2.17	7.60
Victorville	Don	4.16	0.06	0.10	0.08	0.39	0.13	0.50
Stewart	Donald	12.0	1.72	2.48	3.93	14.38	7.82	21.22
Savage	Donert	12.0	0.51	0.62	0.79	3.43	1.02	4.02
Somis	Donlon	16.0	0.52	0.58	0.73	3.31	1.35	4.17
Carson	Donna	16.0	0.22	0.31	0.35	2.89	0.36	3.46
Ivyglen	Donner	12.0	0.20	0.35	0.33	2.74	0.34	3.29
Cucamonga	Donohue	12.0	0.86	1.03	1.27	6.19	2.06	7.73
Del Rosa	Dooley	12.0	0.36	0.58	0.54	3.28	0.82	3.91
MacArthur	Doolittle	12.0	0.27	0.32	0.31	2.80	0.62	3.85
Earlimart	Doran	12.0	0.34	0.53	0.52	3.69	0.61	4.26
Villa Park	Dorchester	12.0	0.48	0.86	0.69	4.23	0.99	4.71
La Veta	Doris	12.0	0.39	0.67	0.56	3.40	0.81	3.92
Elsinore	Dorman	12.0	0.85	1.47	1.20	7.07	1.88	8.78
Eric	Dornes	12.0	0.73	0.86	1.06	6.72	1.49	8.01
Skylark	Dorof	12.0	0.32	0.72	0.45	3.33	0.75	4.87
Alder	Dorsey	12.0	0.41	0.88	0.59	5.50	0.70	6.68
Daisy	Dot	4.16	0.16	0.27	0.22	1.67	0.26	1.98
Hanford	Douty	4.16	0.00	0.00	0.00	0.00	0.00	0.01
Sullivan	Dover	4.16	0.18	0.27	0.29	1.73	0.30	1.97
Windsor Hills	Dowell	4.16	0.03	0.10	0.01	0.69	0.01	1.12
Oldfield	Doyle	4.16	0.03	0.08	0.03	0.53	0.04	0.78
Repetto	Dozier	16.0	0.05	0.09	0.08	0.51	0.09	0.57
Santiago	Drachma	12.0	0.70	1.42	1.10	8.27	1.24	9.02
Porterville	Drag	12.0	1.17	1.41	1.74	6.56	2.48	7.98

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
San Bernardino	Dragon	12.0	0.51	0.83	0.81	5.70	0.91	5.90
Pixley	Drake	12.0	0.43	0.66	0.64	4.58	1.05	5.94
Milliken	Drambuie	12.0	0.68	0.87	1.07	6.34	1.32	7.26
Dike	Dredge	12.0	0.28	0.51	0.45	5.06	0.48	6.98
Homart	Dressen	12.0	0.43	0.79	0.64	4.31	0.82	4.72
Bryan	Dreyer	12.0	0.37	0.93	0.41	3.99	1.09	7.33
Neptune	Drift	12.0	2.53	3.65	6.76	18.61	15.02	31.56
Wave	Driftwood	12.0	0.33	0.74	0.37	5.64	0.47	6.71
Bowl	Drill	4.16	0.05	0.09	0.07	0.61	0.09	0.72
Olinda	Driller	12.0	0.39	0.77	0.52	3.82	0.86	5.29
San Marcos	Driskill	16.0	0.38	0.85	0.38	5.75	0.54	7.58
Inyokern	Driveinn	12.0	0.22	0.28	0.33	2.06	0.38	2.65
Delano	Driver	12.0	0.92	1.35	2.44	6.37	5.86	11.83
Shuttle	Droid	12.0	0.54	0.66	0.74	3.40	1.61	4.87
Genamic	Drone	12.0	0.48	0.71	0.64	4.95	1.27	7.45
Telegraph	Drum	12.0	0.32	0.48	0.44	2.54	0.83	3.44
Saugus	Drycanyon	16.0	1.18	1.58	1.88	9.42	2.16	10.59
Cottonwood	Drylands	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Santiago	Ducat	12.0	0.76	1.58	1.15	8.47	1.56	10.19
Terra Bella	Ducor	12.0	0.28	0.43	0.39	2.02	0.58	2.59
Maxwell	Duda	12.0	0.61	1.41	0.88	7.41	1.10	8.09
San Marcos	Duffer	16.0	1.94	3.40	4.85	17.75	10.63	26.38
Duhon P.T.	Duhon	4.16	0.02	0.05	0.01	0.44	0.01	0.74
Maraschino	Duke	12.0	0.30	0.68	0.24	5.45	0.45	6.92
Cardiff	Dumas	12.0	0.64	0.79	0.94	3.55	1.52	4.31
Somerset	Dunbar	4.16	0.09	0.16	0.11	0.89	0.14	1.17
South Gate	Duncan	4.16	0.16	0.21	0.24	1.44	0.26	1.55
Wabash	Dundas	16.0	0.24	0.45	0.35	2.41	0.45	2.74
Venida	Dungan	12.0	0.94	1.36	1.26	5.26	2.66	7.25
Puente	Dunkirk	12.0	0.53	0.81	0.75	4.82	1.15	6.48
Homart	Dunlap	12.0	0.50	0.91	0.72	4.46	1.05	5.15
Randall	Dunning	12.0	0.43	0.82	0.58	4.66	0.92	6.36
Woodruff	Dunrobin	4.16	0.15	0.19	0.21	1.22	0.36	1.56
Neenach	Duntley	12.0	0.09	0.11	0.14	0.82	0.16	0.89
Cabrillo	Dupont	12.0	0.57	1.34	0.92	7.84	0.96	8.12
Culver	Durango	4.16	0.12	0.21	0.17	1.14	0.23	1.26
Bartolo	Durfee	4.16	0.08	0.14	0.12	0.95	0.16	1.17
Bovine	Durham	12.0	0.75	0.69	1.06	4.77	1.81	5.89
Timoteo	Durox	12.0	0.51	1.03	0.79	5.86	0.95	6.34
Layfair	Durward	12.0	0.67	0.77	0.97	4.56	1.64	5.86
Cherry	Dusk	12.0	0.07	0.17	0.11	1.03	0.13	1.18
Rio Hondo	Dusty	16.0	0.15	0.27	0.22	1.61	0.30	1.79
Quartz Hill	Dweezil	12.0	0.39	0.64	0.58	2.95	0.91	3.93
Sharon	Dyer	4.16	-0.01	0.00	-0.07	0.57	-0.06	0.88
Genamic	Dynamics	12.0	0.59	0.92	0.93	7.90	1.01	9.55
Dysart P.T.	Dysart	12.0	0.03	0.06	0.04	0.25	0.05	0.35
Kramer	Dyson	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Talbert	Eagle	12.0	0.72	0.93	1.14	7.20	1.31	7.87
Eagle Crest	Eaglecrest	12.0	0.03	0.05	0.05	0.38	0.05	0.38
Victor	Egleranch	12.0	0.36	0.45	0.57	3.74	0.66	5.64
Bowl	Earl	4.16	0.10	0.17	0.13	0.97	0.17	1.13
Cucamonga	Earnhardt	12.0	0.61	0.81	0.91	4.55	1.30	5.78
Mt. Pass	Earth	12.0	0.03	0.04	0.04	0.20	0.06	0.22
Delano	Eastcity	4.16	0.07	0.09	0.13	0.63	0.20	0.77
Peyton	Eastend	12.0	0.97	1.59	1.57	8.73	2.20	10.13
Nelson	Easter	12.0	0.73	0.81	1.01	4.42	2.14	6.06
Stirrup	Eastfield	4.16	0.05	0.31	0.03	1.09	0.08	2.15
Bandini	Eastland	16.0	0.39	0.52	0.62	3.95	0.69	4.47
Bicknell	Eastmont	4.16	0.14	0.19	0.21	1.30	0.22	1.42
San Vicente	Eastmontana	4.16	0.12	0.17	0.19	1.53	0.19	2.51
Wilsona	Eastwind	12.0	0.17	0.27	0.27	1.68	0.28	1.70
Davidson City	Easy	4.16	0.16	0.24	0.24	1.58	0.26	1.81
Pico	Ebbtide	12.0	0.15	0.30	0.25	1.97	0.25	2.30
Lakewood	Ebell	4.16	0.06	0.11	0.06	1.07	0.08	1.43
Fogarty	Ebert	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Torrance	Ebony	16.0	0.44	0.71	0.53	5.53	0.67	6.68
Del Rosa	Echo	12.0	0.34	0.55	0.48	2.67	0.92	3.64
Estrella	Eclipse	12.0	0.77	1.39	1.13	8.26	1.49	9.97
Ely	Ecuador	12.0	0.49	0.61	0.68	3.98	1.23	5.20

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Tipton	Edendale	12.0	0.16	0.28	0.24	2.20	0.29	2.91
Alon	Edgar	12.0	0.61	0.79	0.98	6.09	1.10	7.29
Fairfax	Edinburg	16.0	0.33	0.44	0.50	2.35	0.66	2.67
Ivar	Edmond	4.16	0.10	0.14	0.14	0.91	0.23	1.13
Vera	Edsel	12.0	0.72	0.88	1.02	4.31	1.64	5.46
Alessandro	Edwin	12.0	0.57	0.71	0.85	3.97	1.25	4.80
Oak Grove	Effie	12.0	1.01	1.50	1.64	12.37	1.66	12.43
Beaumont	Egan	4.16	0.06	0.10	0.08	0.48	0.12	0.55
Cortez	Egmont	12.0	0.65	0.69	0.92	3.98	1.60	5.13
Ripley	Eighteenth	12.0	0.09	0.11	0.12	0.42	0.27	0.62
Elaine P.T.	Elaine	2.4	0.00	-0.01	-0.01	0.00	0.00	0.00
Palm Canyon	Elcamino	4.16	0.09	0.14	0.15	0.81	0.16	0.84
Garfield	Elcentro	4.16	0.07	0.10	0.10	0.73	0.12	1.02
Irvine	Elden	12.0	0.06	0.08	-0.05	1.53	0.05	2.18
Rialto	Elder	12.0	0.45	0.78	0.65	3.95	0.95	4.69
Los Cerritos	Eldridge	4.16	0.05	0.17	0.03	1.01	0.03	1.64
Lark Ellen	Eleanor	12.0	0.44	0.51	0.63	2.61	1.11	3.27
Lockheed	Electra	16.0	1.74	2.59	4.46	14.84	9.90	22.69
Culver	Electric	16.0	0.17	0.33	0.26	2.07	0.30	2.22
Elementary P.T.	Elementary	4.16	0.03	0.03	0.03	0.19	0.11	0.38
Lampson	Elephant	12.0	0.86	1.94	1.38	11.22	1.49	11.63
Beverly	Elevado	4.16	0.12	0.25	0.15	0.97	0.33	1.68
Granada	Elgin	4.16	-0.01	0.05	-0.06	0.42	-0.06	0.95
Blythe City	Elhers	4.8	0.08	0.19	0.12	0.69	0.20	1.10
Octol	Elk	12.0	0.58	0.72	0.88	5.04	1.34	6.48
Belmont	Elko	4.16	0.09	0.14	0.13	0.77	0.16	0.87
Lucas	Elkport	12.0	0.73	1.57	1.02	8.74	1.27	10.04
Rolling Hills	Ellenwood	16.0	1.29	1.91	2.06	10.86	2.30	11.16
Delano	Ellington	12.0	0.65	0.87	0.95	4.50	1.40	5.54
Arro	Elliot	4.16	0.13	0.19	0.18	0.89	0.29	1.09
Lancaster	Elm	4.16	0.05	0.05	0.07	0.33	0.09	0.38
Eaton	Elmer	16.0	0.22	0.78	0.19	4.39	0.29	6.31
Costa Mesa	Elmira	4.16	0.05	0.20	0.05	0.94	0.05	1.59
Strathmore	Elmirador	12.0	0.24	0.40	0.29	2.41	0.49	3.51
Browning	Elmo	12.0	0.10	0.13	0.16	0.87	0.22	0.96
Amador	Elmonte	4.16	0.09	0.14	0.16	1.03	0.23	1.21
Oak Grove	Elowin	12.0	0.46	0.83	0.56	3.91	1.18	5.18
Cabrillo	Elpac	12.0	0.28	0.64	0.44	3.67	0.47	3.83
Redondo	Elpaseo	4.16	0.06	0.11	0.10	0.99	0.11	1.71
Soquel	Elprado	12.0	0.42	0.44	0.53	2.78	1.35	4.31
Oxnard	Elrio	4.16	0.12	0.17	0.19	1.22	0.21	1.40
La Fresa	Elroy	16.0	0.96	1.21	1.50	7.57	1.83	7.95
Boxwood	Elster	12.0	0.46	0.93	0.63	3.75	1.09	5.74
Alessandro	Elsworth	12.0	0.61	0.81	0.95	4.69	1.17	5.30
Irvine	Eltoro	12.0	0.42	0.66	0.61	4.81	0.75	6.62
Emigrant P.T.	Emigrant	12.0	0.03	0.06	0.05	0.32	0.05	0.34
Stewart	Emory	12.0	0.23	0.30	0.31	1.23	0.57	1.62
San Marcos	Empire	16.0	0.69	1.26	1.02	7.12	1.28	7.69
Ontario	Emporia	4.16	0.12	0.21	0.17	1.07	0.26	1.32
O'neill	Empresa	12.0	0.33	1.18	0.46	5.93	0.51	8.04
Fruitland	Emsco	16.0	1.14	1.54	1.78	9.02	2.24	9.98
Isla Vista	Encanto	16.0	0.52	1.07	0.67	7.43	0.80	8.26
Royal	Enchanted	16.0	0.90	1.17	1.44	7.57	1.55	8.45
Encinas P.T.	Encinas	4.16	0.00	0.01	0.00	0.03	0.00	0.05
Ravendale	Endicott	4.16	0.11	0.07	0.13	0.52	0.40	0.97
Shuttle	Endor	12.0	0.30	0.47	0.43	2.39	0.71	3.33
Chatsworth	Energy	16.0	0.27	0.79	0.34	3.98	0.42	5.62
Railroad	Engine	12.0	0.57	0.78	0.92	5.31	1.01	8.05
Inglewood	England	4.16	0.05	0.09	0.07	0.58	0.08	0.72
Sullivan	English	12.0	0.78	0.94	1.13	4.79	1.69	5.79
Dalton	Enid	12.0	0.41	0.66	0.63	5.82	0.72	6.90
Amador	Enloe	16.0	0.79	1.41	1.15	7.63	1.58	8.91
Huntington Park	Ensign	4.16	0.11	0.14	0.16	1.01	0.17	1.10
Levy	Enterprise	16.0	1.37	1.71	2.11	12.96	2.74	15.75
Thornhill	Entrada	12.0	1.09	1.35	1.71	7.58	2.06	8.41
Carson	Epsilon	16.0	0.94	1.23	1.34	6.48	2.71	9.03
Sun City	Equinox	12.0	0.15	0.27	0.22	1.34	0.36	1.72
Bowl	Erie	4.16	0.16	0.27	0.23	1.40	0.29	1.63
Mayberry	Erin	12.0	0.51	0.97	0.74	4.95	1.11	6.16

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Royal	Erringer	16.0	0.53	0.88	0.72	4.88	1.21	6.54
Isabella	Erskine	12.0	0.78	1.11	1.11	5.05	1.74	6.45
Escala P.T.	Escala	12.0	0.03	0.11	0.05	0.44	0.05	0.72
La Mirada	Escalona	12.0	0.43	0.57	0.69	3.55	0.76	3.63
Narrows	Escamilla	12.0	0.52	0.98	0.79	5.56	1.02	6.36
Escondido P.T.	Escondido	12.0	0.01	0.02	0.02	0.08	0.03	0.12
Holiday	Escuela	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Coffee	Espresso	12.0	0.51	0.97	0.73	4.58	1.08	6.61
Vera	Essex	12.0	1.66	2.16	4.04	12.82	8.75	20.47
Somis	Estaban	16.0	0.52	1.26	0.64	6.45	0.84	9.53
Repetto	Estates	4.16	0.07	0.09	0.10	0.58	0.18	0.71
Bowl	Esther	4.16	0.16	0.34	0.23	1.81	0.29	2.01
Stoddard	Estreet	4.16	0.01	0.01	0.01	0.03	0.02	0.04
Valley	Ethanac	12.0	0.40	0.84	0.62	5.01	0.78	6.20
Ettalee P.T.	Ettalee	4.16	0.01	0.01	0.01	0.04	0.01	0.05
Levy	Etting	16.0	0.53	0.66	0.82	5.23	1.04	6.47
Peyton	Eucalyptus	12.0	0.30	0.39	0.35	2.25	1.00	3.92
Rio Hondo	Euphrates	12.0	0.45	0.73	0.68	4.79	0.78	4.95
Santiago	Euro	12.0	0.53	1.04	0.80	5.85	1.00	6.48
Rolling Hills	Evans	16.0	0.92	1.04	1.39	6.16	1.94	6.77
Mira Loma	Everest	12.0	0.36	0.81	0.49	3.43	0.90	5.24
Moorpark	Everett	16.0	0.69	1.09	0.96	5.66	1.46	6.77
South Gate	Evergreen	4.16	0.13	0.25	0.20	1.32	0.22	1.61
Camarillo	Evita	16.0	1.08	1.16	1.62	8.08	2.18	9.41
Pioneer	Excelsior	4.16	0.10	0.11	0.14	0.94	0.24	1.11
Beverly	Executive	16.0	0.53	1.03	0.80	5.25	1.01	5.65
Amador	Exline	16.0	0.97	1.62	1.42	9.42	1.94	10.98
Gisler	Explorer	12.0	0.43	0.62	0.67	3.58	0.80	3.89
Stoddard	Expo	4.16	0.09	0.17	0.14	0.95	0.17	1.07
Barstow	Express	33.0	0.00	0.00	0.00	0.00	0.00	0.01
Firehouse	Extinguisher	12.0	0.45	1.00	0.70	5.95	0.82	6.62
Bridge	Ezra	4.16	0.09	0.13	0.10	0.97	0.14	1.19
Stadler	Facemask	12.0	0.27	0.87	0.30	3.84	0.47	5.91
Yukon	Factor	16.0	0.56	0.69	0.90	5.59	0.96	6.46
Walnut	Factory	12.0	0.86	1.22	1.39	8.79	1.46	11.59
Lucas	Faculty	4.16	0.11	0.08	0.14	0.80	0.34	1.08
Greening	Fagan	12.0	0.61	0.67	0.91	4.31	1.31	5.05
Santa Barbara	Fairacres	4.16	0.09	0.12	0.12	0.62	0.19	0.81
Yukon	Fairbanks	4.16	0.18	0.27	0.22	1.10	0.35	1.50
Inglewood	Fairhaven	16.0	1.37	1.93	2.09	10.48	2.85	12.06
Lindsay	Fairlawn	4.16	0.04	0.06	0.06	0.36	0.07	0.44
Sunnyside	Fairman	12.0	0.38	0.53	0.60	3.18	0.71	3.57
Del Sur	Fairmont	12.0	0.05	0.06	0.07	0.28	0.12	0.35
Layfair	Fairplex	12.0	0.20	0.50	0.32	3.03	0.33	3.23
Villa Park	Fairway	12.0	0.44	0.97	0.54	4.39	1.12	6.94
Bixby	Falcon	4.16	0.06	0.09	0.10	0.59	0.11	0.65
Ontario	Fallis	4.16	0.14	0.17	0.20	0.55	0.37	0.75
Eric	Fallon	12.0	0.35	0.36	0.45	3.30	0.68	4.02
Falls P.T.	Falls	2.4	0.00	0.00	0.00	0.00	0.00	0.00
Calectric	Famous	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Padua	Fano	12.0	0.57	0.95	0.70	3.65	2.01	6.92
Tahiti	Fantail	16.0	0.52	0.99	0.80	6.09	0.85	6.44
Alessandro	Fantastico	12.0	0.62	1.14	0.85	4.54	1.89	7.14
Clark	Fanwood	4.16	-0.02	0.02	-0.13	0.70	-0.10	1.34
Crown	Farallon	12.0	0.65	1.35	0.98	7.09	1.25	7.63
Hesperia	Fargo	12.0	0.59	0.74	0.88	3.65	1.38	4.46
Newcomb	Farmington	12.0	0.26	0.44	0.35	2.05	0.62	2.80
Oasis	Farms	12.0	0.68	1.00	0.98	5.37	1.47	6.98
Johanna	Faro	12.0	0.34	0.58	0.55	4.47	0.56	4.90
Santiago	Farthing	12.0	0.63	1.21	0.89	8.16	1.13	9.59
Pico	Fashion	12.0	0.00	0.01	0.01	0.06	0.01	0.07
Clark	Faust	4.16	0.03	0.03	0.01	0.72	0.01	0.95
Weldon	Faye	12.0	0.15	0.26	0.21	1.09	0.29	1.43
Sawtelle	Federal	16.0	0.09	0.43	0.15	2.52	0.16	2.62
Wimbledon	Federer	12.0	0.55	0.68	0.86	5.40	0.96	5.96
Cypress	Fela	12.0	0.54	0.77	0.69	4.82	1.19	6.87
Crest	Feldspar	16.0	0.14	0.60	0.12	2.87	0.15	4.80
Los Cerritos	Felix	12.0	0.55	0.69	0.84	3.78	1.15	4.13
Hamilton	Feller	12.0	0.10	0.19	0.10	1.64	0.15	1.95

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Playa	Fellowship	4.16	-0.02	-0.03	-0.07	0.40	-0.07	0.59
Montebello	Ferguson	4.16	0.35	0.42	0.50	1.77	0.89	2.24
Woodruff	Ferina	4.16	0.21	0.25	0.28	1.34	0.51	1.79
Idyllwild	Fern	2.4	0.04	0.10	0.07	0.48	0.08	0.63
Ganesha	Fernstrom	12.0	1.29	1.61	1.94	8.37	2.53	9.57
Archline	Feron	12.0	0.49	0.89	0.70	4.77	1.04	5.86
Padua	Ferrara	12.0	0.52	0.80	0.67	3.99	1.60	6.40
Ellis	Ferree	12.0	0.39	0.56	0.51	3.75	0.77	4.55
Amalia	Fetterly	4.16	0.09	0.17	0.14	0.95	0.16	1.01
Farrell	Fey	12.0	0.52	0.61	0.79	4.53	0.86	4.91
Neptune	Fiat	4.16	0.07	0.12	0.10	0.84	0.12	0.98
Hedda	Fidler	4.16	0.08	0.10	0.09	0.76	0.19	1.05
Walnut	Fieldgate	12.0	0.16	0.16	0.07	2.48	0.38	4.52
Etiwanda	Fields	12.0	1.13	1.62	1.80	9.71	2.02	10.35
Anita	Fiesta	4.16	0.08	0.05	0.09	0.54	0.24	0.81
Colonia	Fifthst.	16.0	1.71	2.15	2.82	16.86	3.29	19.26
Bradbury	Fig	16.0	0.45	0.77	0.68	4.68	0.87	5.24
Santa Barbara	Figueroa	4.16	0.13	0.22	0.17	0.85	0.30	1.07
Bryan	Fiji	12.0	0.57	1.08	0.85	5.65	1.09	6.20
Chestnut	Filbert	12.0	0.53	0.84	0.79	5.54	1.03	6.43
Inglewood	Filly	16.0	0.56	0.73	0.88	4.44	1.07	5.00
Placentia	Finals	12.0	0.65	1.08	0.96	6.12	1.29	6.90
Narod	Finch	12.0	0.73	1.31	0.96	4.40	2.45	7.89
Vail	Findley	16.0	2.86	3.77	8.01	19.62	18.84	36.17
Cabazon	Fingal	12.0	1.66	2.07	2.66	11.70	2.93	12.20
Trophy	Finishline	12.0	0.38	0.44	0.46	3.22	1.08	4.87
Lynwood	Fir	4.16	0.10	0.17	0.14	1.03	0.17	1.16
Torrance	Firethorn	16.0	0.98	1.19	1.45	6.95	2.17	8.18
Viejo	Firme	12.0	0.52	0.93	0.76	5.07	1.02	5.74
La Fresa	Firmona	16.0	0.17	0.23	0.22	1.76	0.27	1.95
Los Cerritos	Firth	12.0	0.01	0.01	0.01	0.01	0.02	0.03
Maywood	Fishburn	4.16	0.04	0.05	0.05	0.37	0.06	0.46
Cucamonga	Fittipaldi	12.0	0.30	0.56	0.43	3.07	0.67	4.03
Chiquita	Fizz	12.0	0.42	0.83	0.59	5.69	0.70	6.76
Rubidoux	Flabob	12.0	0.25	0.41	0.35	2.01	0.53	2.38
Sunnyside	Flagg	12.0	0.55	0.87	0.82	5.10	1.00	5.92
Elsinore	Flagstaff	12.0	0.34	0.79	0.42	3.72	0.90	6.09
Flagstone P.T.	Flagstone	4.16	0.04	0.04	0.04	0.30	0.08	0.39
Maxwell	Flake	12.0	0.34	0.72	0.45	3.67	0.81	5.52
Firehouse	Flame	12.0	0.29	0.50	0.43	3.00	0.54	3.37
La Canada	Flanders	4.16	0.10	0.34	0.11	0.89	0.36	2.08
Sun City	Flare	12.0	0.15	0.32	0.18	1.71	0.36	2.56
Lighthipe	Flask	12.0	0.40	0.49	0.60	2.57	0.85	2.91
Bloomington	Flatcar	12.0	0.68	1.28	1.02	6.99	1.38	8.14
Valley	Flats	12.0	0.24	0.41	0.36	3.41	0.39	3.81
West Riverside	Fleetwood	12.0	0.97	1.16	1.53	7.51	1.86	7.89
Imperial	Fleming	12.0	0.84	1.12	1.30	6.00	1.75	6.90
Eisenhower	Flight	12.0	0.63	0.76	0.93	3.60	1.58	4.55
Trask	Flint	12.0	0.32	0.40	0.50	2.29	0.56	2.44
La Canada	Flintridge	4.16	0.05	0.31	0.05	1.06	0.09	2.06
Seabright	Float	12.0	0.01	0.02	0.02	0.14	0.03	0.16
Aqueduct	Floodgate	12.0	0.66	0.99	0.90	5.40	1.34	7.37
Repetto	Floral	16.0	0.57	0.96	0.79	6.49	1.06	7.56
Cudahy	Florence	16.0	1.98	2.50	3.02	13.99	4.15	16.48
Fairview	Flores	12.0	0.20	0.38	0.29	2.01	0.38	2.25
Carolina	Florida	12.0	0.58	1.05	0.88	6.90	1.04	7.82
Hanford	Florinda	12.0	0.58	0.90	0.81	4.31	1.47	6.05
Woodville	Flory	12.0	0.28	0.48	0.37	2.39	0.61	3.18
Vail	Flotilla	16.0	2.23	2.93	5.25	19.39	10.44	29.23
Edinger	Flower	4.16	0.14	0.19	0.21	1.30	0.23	1.48
Aqueduct	Flue	12.0	0.51	0.63	0.66	3.61	1.30	5.36
Niguel	Flute	12.0	0.55	1.08	0.86	6.09	0.99	6.38
Havilah	Flyingd	12.0	0.06	0.08	0.09	0.52	0.12	0.69
Camarillo	Flynn	16.0	1.27	1.37	1.90	8.77	2.66	10.12
Ditmar	Flywheel	16.0	0.33	0.52	0.43	2.42	0.64	2.96
Chiquita	Fogcutter	12.0	0.03	0.20	-0.14	2.45	-0.05	4.22
Tulare	Fogg	12.0	0.53	0.93	0.78	4.56	1.13	6.04
Bassett	Folger	12.0	0.41	0.53	0.63	4.15	0.88	5.33
La Habra	Fonda	12.0	0.53	0.85	0.77	4.68	1.10	5.31

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Calectric	Fonri	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Stadler	Football	12.0	0.15	0.21	0.18	0.67	0.37	0.98
Stadium	Foote	12.0	0.19	0.31	0.24	2.81	0.33	3.57
San Dimas	Foothill	12.0	0.45	0.53	0.63	3.01	1.11	3.95
Piute	Forage	12.0	0.17	0.29	0.26	2.03	0.28	2.66
Live Oak	Forbes	12.0	0.57	0.38	0.75	3.13	1.54	4.11
Rush	Forbid	16.0	0.89	1.52	1.30	8.97	1.76	10.48
Shuttle	Force	12.0	0.41	0.65	0.60	3.31	0.93	4.50
Dike	Ford	12.0	0.03	0.19	0.05	1.72	0.06	2.63
State Street	Forest	12.0	0.23	0.29	0.35	1.50	0.45	1.63
Santiago	Forint	12.0	0.07	0.17	-0.07	2.41	0.01	3.62
Fairfax	Formosa	16.0	0.30	0.38	0.46	2.16	0.60	2.41
Kimball	Fortress	12.0	0.28	0.52	0.35	3.30	0.64	4.79
Forty Eight St. P.T.	Fortyeightst.	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Ventura	Foster	4.16	0.07	0.10	0.10	0.75	0.11	0.84
Founders P.T.	Founders	4.16	0.02	0.04	0.03	0.28	0.05	0.36
Fairfax	Fountain	4.16	0.05	0.09	0.08	0.54	0.09	0.60
Modoc	Fox	4.16	0.03	0.04	-0.01	0.63	0.03	0.84
Badillo	Foxdale	4.16	0.11	0.17	0.15	0.89	0.32	1.33
Barre	Foxglove	12.0	0.39	0.40	0.55	4.12	0.70	4.58
Cucamonga	Foyt	12.0	0.35	0.58	0.51	3.37	0.72	4.06
Porterville	Frame	4.16	0.28	0.36	0.38	1.33	0.66	1.85
Santiago	Franc	12.0	0.32	0.51	0.41	4.12	0.59	5.01
Colorado	Franklin	16.0	0.30	0.60	0.48	3.80	0.52	4.05
Isla Vista	Fraternity	16.0	0.43	0.82	0.64	4.63	0.76	5.04
Liberty	Freedom	12.0	0.36	1.24	0.50	4.26	1.02	7.20
Oldfield	Freeland	4.16	0.03	0.08	0.04	0.49	0.05	0.65
Lawndale	Freeman	4.16	0.08	0.13	0.10	1.02	0.12	1.16
Declez	Freeway	4.16	0.03	0.07	0.05	0.39	0.05	0.52
Roadway	Freightliner	12.0	0.41	0.72	0.63	5.00	0.78	5.85
Garfield	Fremont	4.16	0.08	0.15	0.11	0.83	0.14	0.94
Santa Fe Springs	Friends	12.0	0.75	0.94	1.15	5.61	1.55	6.07
Doheny	Fringe	4.16	0.12	0.20	0.16	0.72	0.41	1.26
Alder	Frisbie	12.0	0.61	1.00	0.88	5.20	1.49	6.81
Tortilla	Frito	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Savage	Frontage	12.0	0.71	0.85	1.09	4.67	1.45	5.38
Redlands	Frost	12.0	0.40	0.72	0.55	3.85	0.94	5.25
Nelson	Fruitvale	12.0	0.27	0.56	0.41	3.68	0.44	4.46
Watson	Fry	12.0	0.23	0.53	0.36	3.45	0.39	3.91
Fruitland	Fudge	4.16	0.09	0.13	0.13	0.77	0.15	0.86
Nogales	Fuerte	12.0	0.48	0.63	0.63	4.30	1.15	5.98
Browning	Fugate	12.0	0.01	0.02	0.01	0.02	0.04	0.05
Mira Loma	Fujiyama	12.0	0.35	0.71	0.44	3.91	0.81	5.59
Stadler	Fullback	12.0	0.16	0.70	0.16	3.16	0.28	5.49
Fairfax	Fuller	16.0	0.97	1.23	1.53	6.90	1.78	7.24
Junction	Furnacecreek	33.0	0.10	0.20	0.16	1.16	0.16	1.18
Viejo	Futuro	12.0	0.24	0.49	0.31	2.98	0.48	3.86
Moorpark	Gabbert	16.0	0.22	0.57	0.24	3.24	0.34	4.73
Movie	Gable	16.0	0.76	1.79	1.14	9.63	1.44	10.51
Gabrielino P.T.	Gabrielino	4.16	0.02	0.01	0.02	0.21	0.04	0.26
Gaffey P.T.	Gaffey1	2.4	0.07	0.09	0.10	0.54	0.13	0.68
Ravendale	Gainsborough	16.0	0.24	0.44	0.25	3.10	0.40	4.02
Latigo	Galahad	16.0	0.46	1.33	0.51	6.50	0.70	9.87
Glen Avon	Galena	12.0	0.58	0.76	0.77	3.37	1.93	5.17
Galileo P.T.	Galileo	12.0	0.02	0.03	0.03	0.17	0.03	0.18
Maywood	Gallion	4.16	0.00	0.00	0.00	-0.01	0.00	0.04
Palm Village	Gallon	12.0	0.82	1.09	1.22	4.87	1.75	5.88
Lucas	Gallup	4.16	0.17	0.18	0.23	1.17	0.51	1.54
Euclid	Galvin	4.16	0.20	0.25	0.30	1.89	0.47	2.16
Alessandro	Gamble	12.0	0.26	0.51	0.38	3.09	0.50	3.80
Phelan	Gambler	12.0	0.71	0.90	0.98	3.72	2.00	5.45
Telegraph	Gamma	12.0	0.27	0.35	0.37	1.55	0.73	2.06
Farrell	Garbo	12.0	0.66	1.19	0.99	6.37	1.18	7.90
Auld	Garboni	12.0	0.38	1.01	0.38	4.31	0.75	7.10
Visalia	Garcia	12.0	0.60	1.12	0.74	3.87	1.47	5.90
Eric	Gard	12.0	0.14	0.20	0.19	1.53	0.32	1.92
Amador	Gardea	16.0	0.61	1.03	0.89	6.28	1.19	7.33
Santa Barbara	Garden	4.16	0.05	0.04	0.01	0.67	0.05	0.91
Imperial	Gardendale	4.16	0.10	0.12	0.13	1.09	0.15	1.32

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Pomona	Garey	4.16	0.20	0.25	0.30	1.37	0.43	1.59
Clark	Garford	4.16	0.03	0.08	0.02	0.61	0.04	0.88
Anita	Garibaldi	16.0	0.43	0.76	0.52	5.37	0.89	7.35
Cucamonga	Garlits	12.0	0.90	1.14	1.42	7.90	1.61	8.94
Mt. Vernon	Garner	4.16	0.08	0.17	0.13	1.02	0.14	1.17
Cypress	Garnsey	12.0	0.44	0.45	0.60	2.48	1.23	3.58
Archibald	Garrett	12.0	0.52	0.89	0.79	4.93	1.10	5.77
Nogales	Gartel	12.0	0.75	0.98	1.14	6.27	1.59	7.18
Mariposa	Garwood	12.0	0.38	0.56	0.55	3.24	0.72	3.77
La Palma	Garza	12.0	0.40	0.84	0.63	4.94	0.71	5.27
Nola	Gasbag	16.0	0.88	1.35	2.98	6.10	7.65	13.56
Gallatin	Gaspar	12.0	0.24	0.29	0.36	1.63	0.53	1.87
La Habra	Gaston	12.0	0.42	1.04	0.50	4.57	0.81	6.57
Pearl	Gateway	4.16	0.05	0.09	0.05	0.74	0.08	0.93
Walnut	Gatlin	12.0	0.51	0.46	0.72	3.60	1.00	5.01
Vegas	Gaucho	16.0	0.76	1.41	1.13	8.08	1.41	8.90
Newhall	Gavin	16.0	0.65	1.40	0.90	7.34	1.35	9.32
San Antonio	Gaylord	12.0	1.04	1.26	1.56	6.59	2.23	7.44
Lampson	Gazelle	12.0	2.03	3.44	6.07	15.99	14.79	28.73
Industry	Gear	12.0	2.34	3.19	7.01	17.87	16.84	33.56
Felton	Gearline	16.0	1.67	2.07	2.67	12.35	2.91	12.99
Hanford	Geebee	12.0	0.66	0.93	0.94	6.04	1.22	7.65
Hamilton	Gehrig	12.0	0.34	0.39	0.45	1.61	0.92	2.24
Topaz	Gem	4.16	0.03	0.02	0.02	0.44	0.02	0.58
La Fresa	Generalpetroleum	16.0	1.38	1.83	3.81	9.92	8.80	17.67
Wave	Geneva	4.16	0.03	0.06	0.02	0.73	0.03	0.87
Santa Monica	Georgian	4.16	0.06	0.12	0.09	0.61	0.12	0.66
Lucas	Geraths	12.0	0.19	0.40	0.29	2.20	0.36	2.34
Rosemead	Gerona	16.0	0.81	1.22	1.11	6.38	1.74	7.84
Lark Ellen	Gertrude	12.0	0.73	0.89	1.13	5.64	1.44	6.01
Slater	Giants	12.0	0.49	0.99	0.73	9.06	0.79	11.79
Pomona	Gibbs	4.16	0.11	0.18	0.16	0.97	0.28	1.25
Bullis	Gibson	16.0	0.18	0.33	0.26	1.76	0.33	2.05
Visalia	Giddings	12.0	0.51	0.64	0.76	3.21	1.05	3.72
Maywood	Gifford	4.16	0.00	0.01	-0.01	-0.01	0.01	0.08
Riverway	Gila	12.0	0.59	1.02	0.88	5.75	1.21	7.61
Alder	Gilfillan	12.0	0.70	0.87	1.07	5.54	1.57	6.56
Venida	Gill	12.0	0.58	1.06	0.75	5.75	1.15	6.71
Strathmore	Gillette	12.0	0.19	0.40	0.23	1.58	0.40	2.24
Santa Susana	Gillibrand	16.0	0.54	1.07	0.64	4.74	1.53	8.19
La Palma	Gillis	12.0	0.19	0.38	0.28	2.32	0.32	2.53
Ridgeview P.T.	Gilman	12.0	0.10	0.26	0.16	1.49	0.17	1.51
Fairfax	Gilmore	4.16	0.13	0.15	0.17	0.70	0.34	1.02
Blythe City	Gin	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Moreno	Ginger	12.0	0.37	0.62	0.52	3.18	0.98	4.37
Nelson	Girard	12.0	0.35	0.62	0.55	4.06	0.64	4.40
Bridge	Girder	4.16	0.12	0.18	0.15	1.38	0.18	1.64
Channel Island	Gizmo	16.0	0.51	1.02	0.65	6.60	0.82	7.44
Corona	Glacier	12.0	0.68	1.19	0.98	6.96	1.36	8.80
Isla Vista	Gladiola	16.0	0.22	0.44	0.33	2.38	0.38	2.53
San Dimas	Gladstone	12.0	1.17	1.39	1.75	7.10	2.68	8.23
Rosemead	Gladys	16.0	0.92	1.46	1.34	9.47	1.86	11.60
Inglewood	Glasgow	4.16	0.08	0.17	0.12	0.95	0.14	1.15
Laguna Bell	Glass	16.0	0.27	0.33	0.43	2.68	0.46	2.72
Santa Susana	Glasscock	16.0	0.39	0.62	0.49	3.78	0.93	5.50
Repetto	Gleason	16.0	0.55	0.87	0.79	5.07	1.09	5.86
Longdon	Glencoe	4.16	0.18	0.22	0.26	1.33	0.43	1.54
Ramona	Glendon	4.16	0.13	0.18	0.18	0.93	0.31	1.13
Peyton	Glenridge	12.0	0.41	0.74	0.66	4.43	0.94	5.29
La Palma	Glidden	12.0	0.41	0.91	0.57	4.42	0.76	4.85
Stetson	Glider	12.0	0.27	0.49	0.35	3.20	0.48	4.11
Colton	Globemills	12.0	0.53	0.86	0.89	6.98	1.22	9.10
Arcadia	Gloria	16.0	0.50	0.97	0.70	4.98	1.03	6.19
Octol	Glover	12.0	0.66	0.83	0.97	4.98	1.55	6.41
Cottonwood	Gobar	33.0	0.01	0.02	0.02	0.14	0.02	0.16
Quartz Hill	Godde	12.0	0.44	0.84	0.61	4.01	0.93	5.68
Newcomb	Goetz	12.0	0.33	0.88	0.43	3.61	0.93	6.25
Limestone	Gold	12.0	0.43	0.71	0.69	5.04	0.74	5.21
Highland	Goldbuckle	12.0	0.48	0.80	0.69	4.37	1.18	5.81

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Locust	Golden	4.16	0.08	0.13	0.12	0.78	0.14	0.87
Mascot	Goldenbear	12.0	0.34	0.55	0.49	2.78	0.86	3.84
Michillinda	Goldenwest	4.16	0.13	0.20	0.16	0.91	0.28	1.25
Thousand Oaks	Goldsmith	16.0	0.35	0.88	0.39	4.83	0.57	7.26
MacArthur	Goldwater	12.0	0.50	0.70	0.67	5.01	1.09	6.28
Culver	Goldwyn	4.16	0.01	-0.05	-0.09	0.89	-0.05	1.24
Railroad	Gondola	12.0	0.69	0.80	1.03	4.49	1.45	6.15
Mt. Vernon	Goodner	4.16	0.10	0.18	0.15	0.93	0.19	1.10
Wheatland	Gopher	12.0	0.22	0.37	0.33	2.60	0.39	2.99
Viejo	Gordo	12.0	0.37	0.57	0.59	4.48	0.63	4.64
Rector	Gordon	12.0	0.29	0.83	0.37	3.97	0.71	5.94
Arroyo	Gorge	16.0	0.24	0.60	0.28	4.10	0.36	5.40
Victor	Goss	12.0	0.39	0.39	0.50	2.04	1.22	3.51
Floraday	Gotham	4.16	0.11	0.13	0.13	0.92	0.32	1.39
Glen Avon	Gowan	12.0	0.60	1.11	0.86	5.40	1.38	6.78
La Habra	Grace	12.0	0.30	0.50	0.40	4.05	0.48	4.21
Placentia	Graduate	12.0	0.52	0.84	0.79	5.76	0.96	6.30
Wimbledon	Graf	12.0	0.96	1.17	1.51	7.72	1.80	8.74
Maxwell	Graham	12.0	0.45	0.72	0.61	3.62	1.32	5.46
Sepulveda	Grand	4.16	0.03	0.05	0.04	0.27	0.05	0.30
Casitas	Grandad	16.0	0.10	0.12	0.14	0.50	0.28	0.72
Concho	Grande	12.0	0.57	0.82	0.86	4.30	1.30	5.61
Yukon	Grandview	4.16	0.10	0.16	0.14	1.13	0.15	1.32
Porterville	Granite	12.0	0.58	0.96	0.84	4.57	1.16	5.88
El Casco	Grannysmith	12.0	0.12	0.19	0.18	1.26	0.25	1.70
Lucas	Grant	4.16	0.14	0.12	0.18	1.01	0.41	1.32
Fernwood	Grape	16.0	0.36	0.59	0.54	3.29	0.72	3.66
Citrus	Grapefruit	12.0	0.72	0.86	1.05	4.21	1.80	5.27
Grapevine P.T.	Grapevine	12.0	0.01	0.01	0.02	0.06	0.02	0.07
Limestone	Graphite	12.0	0.15	0.21	0.24	1.75	0.26	1.83
Chiquita	Grasshopper	12.0	0.12	0.91	0.04	4.05	0.08	7.46
Dalton	Gravel	12.0	0.79	1.03	1.18	6.38	1.66	8.16
Alhambra	Graves	4.16	0.04	0.09	0.04	0.47	0.10	0.81
La Fresa	Graveyard	16.0	0.25	0.41	0.33	2.64	0.40	2.92
Anita	Graydon	16.0	0.31	0.80	0.30	4.56	0.56	6.93
Morningside	Grayson	4.16	0.24	0.30	0.35	1.64	0.52	1.93
Walnut	Grazide	12.0	0.82	0.98	1.27	6.91	1.61	9.64
Calcity 'A'	Greasewood	12.0	0.32	0.61	0.44	2.94	0.69	3.88
Bliss	Green	12.0	0.57	0.73	0.89	5.99	1.08	7.47
Hemet	Greenacres	12.0	0.38	0.64	0.63	3.88	0.95	4.72
Slater	Greenbay	12.0	0.15	0.55	0.09	3.87	0.17	5.74
Green Bear P.T.	Greenbear	2.4	0.05	0.07	0.07	0.46	0.10	0.55
Estero	Greenhouse	16.0	0.00	0.00	0.00	0.03	0.00	0.03
Canyon	Greenriver	12.0	0.29	0.49	0.48	4.10	0.57	5.96
Victorville	Greentree	12.0	0.42	0.49	0.70	2.71	0.95	3.12
Green Valley P.T.	Greenvalley	4.16	0.07	0.09	0.12	0.67	0.16	0.87
Montebello	Greenwood	4.16	0.13	0.19	0.18	1.24	0.26	1.51
Yermo	Greer	12.0	0.12	0.23	0.17	0.94	0.24	1.23
Anita	Gregg	16.0	0.36	0.54	0.41	4.02	0.74	5.47
Downs	Gregory	12.0	0.32	0.45	0.44	2.32	0.78	3.17
Eisenhower	Grenade	12.0	0.59	0.86	0.89	4.28	1.35	5.58
Marion	Greta	12.0	0.38	0.71	0.57	3.96	0.74	4.44
Garfield	Grevelia	4.16	0.09	0.13	0.10	0.73	0.22	1.12
Archline	Grey	12.0	0.29	0.74	0.40	3.45	0.72	5.35
Moulton	Greyhound	12.0	0.21	0.37	0.21	3.80	0.28	4.67
Bradbury	Grhartman	16.0	0.00	0.00	0.00	0.00	0.00	0.00
Stadler	Gridiron	12.0	0.53	0.98	0.76	5.07	1.17	6.28
Eric	Gridley	12.0	0.61	0.76	0.91	3.88	1.38	4.66
Nogales	Gridlock	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Chase	Griffin	12.0	0.15	0.60	0.17	2.68	0.21	4.55
Archline	Grilley	12.0	0.47	0.92	0.61	4.30	1.31	6.89
Grimshaw P.T.	Grimshaw	2.4	0.01	0.14	0.02	0.24	0.05	0.68
Industry	Grinder	12.0	1.22	1.48	1.89	9.23	2.46	10.34
San Miguel	Gringo	16.0	1.41	1.79	2.04	9.10	3.15	10.72
El Nido	Grizzley	16.0	1.29	2.39	1.86	14.84	2.13	15.94
Camp 10	Grouse	7.0	0.00	0.01	0.00	0.04	0.00	0.04
Rosamond	Grubstake	12.0	0.58	0.89	0.93	5.63	0.99	6.60
Bayside	Grunion	12.0	0.49	0.84	0.69	4.05	1.05	4.76
Skylark	Gruwell	12.0	0.53	0.96	0.74	4.78	1.24	6.34

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Trask	Guam	12.0	1.05	1.20	1.56	7.34	2.08	8.37
Stadler	Guard	12.0	0.55	0.90	0.77	4.22	1.20	5.03
Upland	Guasti	12.0	0.62	1.15	0.90	6.13	1.31	7.58
Oxnard	Guava	4.16	0.14	0.20	0.19	1.21	0.24	1.39
Tulare	Guernsey	12.0	0.61	1.35	0.84	6.01	1.58	8.08
Ramona	Guest	4.16	0.04	0.02	0.03	0.65	0.06	0.85
Skylark	Guffy	12.0	0.47	0.75	0.68	4.53	1.04	5.77
Genamic	Guidance	12.0	2.27	4.59	7.69	24.57	19.57	51.22
Santiago	Guilder	12.0	0.71	1.34	1.03	7.02	1.41	7.99
Jefferson	Guinness	12.0	0.50	0.77	0.65	3.78	1.47	5.89
Westgate	Guirado	4.16	0.08	0.10	0.11	0.64	0.21	0.81
Elizabeth Lake	Guitar	16.0	0.64	1.20	0.97	6.86	1.16	7.16
Neptune	Gulf	4.16	0.09	0.13	0.13	0.99	0.15	1.16
Parkwood	Gum	12.0	0.29	0.66	0.32	4.47	0.46	5.65
Signal Hill	Gundry	4.16	0.10	0.12	0.11	1.05	0.16	1.32
Bullis	Gunlock	4.16	0.21	0.34	0.27	1.42	0.42	1.86
Gunsite P.T.	Gunsite	2.4	0.01	0.02	0.02	0.09	0.02	0.09
Crown	Gunther	12.0	0.52	0.99	0.77	5.37	1.13	6.30
Cucamonga	Gurney	12.0	0.52	1.04	0.75	6.12	1.03	7.72
Olinda	Gusher	12.0	0.48	0.70	0.66	4.42	1.07	5.64
Northwind	Gust	12.0	0.08	0.11	0.11	0.83	0.15	0.91
Del Rosa	Guthrie	12.0	0.65	0.98	0.90	4.12	1.60	5.35
Santa Barbara	Gutierrez	4.16	0.07	0.23	0.05	1.39	0.08	2.08
Canyon	Gypsum	12.0	0.08	0.43	0.05	2.27	0.12	3.93
Potrero	Hacienda	16.0	0.75	0.89	0.85	5.06	2.43	8.78
Bliss	Hack	12.0	0.23	0.31	0.34	2.09	0.54	2.74
Parkwood	Hackberry	12.0	0.47	1.01	0.65	5.37	1.01	7.19
Maxwell	Hackler	12.0	0.54	0.89	0.77	4.44	1.35	5.87
Searles	Hackman	33.0	0.01	0.01	0.01	0.02	0.02	0.04
Walnut	Hahn	12.0	0.27	0.50	0.39	2.87	0.49	4.04
Cortez	Haig	12.0	0.70	0.84	1.00	4.21	1.87	5.66
Ely	Haiti	12.0	0.65	0.82	1.01	6.13	1.23	7.17
Dike	Hale	12.0	0.04	0.06	0.07	0.52	0.08	0.73
Estrella	Haley	12.0	1.26	1.90	3.85	11.82	9.22	21.27
Stadler	Halfback	12.0	0.41	0.83	0.57	4.17	0.89	5.65
Cypress	Halibut	12.0	0.71	0.87	1.05	4.18	1.52	5.04
Brighton	Halldale	16.0	1.17	1.81	3.03	10.38	6.98	17.44
Inglewood	Hallet	16.0	0.55	0.71	0.84	4.19	1.12	4.80
Shandin	Hallmark	12.0	0.36	0.58	0.58	4.73	0.59	5.34
Villa Park	Hallsworth	12.0	0.57	1.00	0.82	5.47	1.23	6.51
MacArthur	Halsey	12.0	0.37	1.01	0.57	5.13	0.59	6.65
Los Cerritos	Halter	12.0	0.76	0.96	1.17	5.14	1.57	5.60
Ganesha	Hambone	12.0	0.01	0.01	0.01	0.04	0.03	0.06
Repetto	Hammell	16.0	0.42	0.71	0.59	3.46	0.90	4.16
Triton	Hammerhead	12.0	0.16	0.34	0.20	2.21	0.43	3.41
Alessandro	Hammock	33.0	0.41	0.55	0.67	3.26	0.67	3.37
Thousand Oaks	Hampshire	16.0	0.53	1.11	0.60	6.24	0.92	9.03
Granada	Hampton	4.16	0.05	0.09	0.07	0.68	0.08	0.79
Alon	Hancock	12.0	0.49	0.67	0.78	4.95	0.88	5.93
Railroad	Handcar	12.0	0.89	1.30	1.41	6.96	1.67	9.51
Villa Park	Handy	12.0	0.49	1.15	0.58	4.43	1.36	7.79
Browning	Hanes	12.0	0.06	0.08	0.09	0.59	0.11	0.63
Oasis	Hanger	12.0	0.75	1.31	1.20	9.31	1.25	10.31
Cucamonga	Hanks	12.0	1.08	1.36	1.71	10.87	1.93	12.60
Shuttle	Hansolo	12.0	0.74	1.29	1.12	7.39	1.29	8.23
Neptune	Harbor	4.16	0.09	0.13	0.12	1.27	0.12	1.50
Lakewood	Harco	4.16	0.11	0.19	0.13	1.43	0.17	1.86
Center	Hardhat	12.0	0.64	0.79	0.93	3.30	1.51	4.07
Oro Grande	Hardrock	12.0	3.87	5.09	30.57	79.41	6.39	45.20
Linden	Hardwick	4.16	0.14	0.22	0.19	1.15	0.26	1.36
Lennox	Hardy	4.16	0.10	0.17	0.14	1.00	0.17	1.14
Ditmar	Harkness	4.16	-0.03	0.09	-0.12	0.91	-0.12	1.66
Cardiff	Harlemsprings	12.0	0.67	0.86	1.17	5.36	1.64	6.08
Chase	Harlow	12.0	0.99	1.29	1.56	8.57	1.94	9.67
Niguel	Harmonica	12.0	0.16	0.41	0.25	2.57	0.25	2.63
Bliss	Harmony	12.0	0.40	0.65	0.59	4.55	0.73	5.89
Newcomb	Harnage	12.0	0.32	1.00	0.45	4.98	0.55	7.20
Costa Mesa	Harper	4.16	0.07	0.16	0.09	0.94	0.10	1.31
Griswold	Harps	4.16	0.03	0.04	0.02	0.01	0.16	0.31

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Doheny	Harratt	4.16	0.04	0.18	0.05	0.72	0.05	1.24
Goshen	Harrell	12.0	0.78	0.99	1.20	8.20	1.57	10.76
Bunker	Harrier	12.0	0.37	0.70	0.54	4.23	0.71	5.17
Stoddard	Harris	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Wabash	Harrison	16.0	0.64	1.16	0.98	7.19	1.15	7.76
Rector	Hart	12.0	0.38	0.63	0.54	3.52	0.83	4.09
Cudahy	Hartle	4.16	0.14	0.24	0.22	1.47	0.24	1.68
Pierpont	Hartman	4.16	0.03	0.04	0.04	0.50	0.05	0.59
Fullerton	Harvard	4.16	0.04	0.11	0.05	0.75	0.06	0.96
Eric	Harvest	12.0	0.38	0.52	0.58	2.82	0.83	3.26
Inyokern Town	Harveyfield	4.8	0.01	0.02	0.01	0.13	0.02	0.13
Tenaja	Harwood	12.0	0.26	0.58	0.33	2.87	0.64	4.51
Arroyo	Haskell	16.0	0.76	1.76	0.89	7.62	1.44	11.07
Mentone	Hass	12.0	0.49	1.02	0.69	5.45	0.90	7.13
Redlands	Hastings	4.16	0.12	0.41	0.16	0.98	0.39	2.16
Randall	Hasty	12.0	0.39	0.54	0.53	3.43	0.98	4.59
Savage	Hatchery	12.0	0.62	0.74	0.97	3.97	1.16	4.36
Porterville	Hatfield	12.0	0.65	1.09	0.92	4.66	1.64	6.79
Imperial	Hatter	12.0	0.50	0.61	0.74	3.18	1.14	3.81
Hathaway	Havana	12.0	0.38	0.72	0.55	4.07	0.72	4.68
Arcadia	Haven	4.16	0.05	0.03	0.05	0.67	0.07	0.74
La Habra	Havenhurst	12.0	0.77	0.98	1.23	7.36	1.32	7.47
Cypress	Hawaiian	4.16	0.11	0.14	0.16	0.95	0.24	1.10
Talbert	Hawk	12.0	0.92	1.12	1.39	7.73	1.58	8.76
Upland	Hawkins	12.0	0.48	0.82	0.69	4.60	1.02	5.70
Yukon	Hawthorne	16.0	1.19	1.58	1.83	8.60	2.48	9.79
Inglewood	Hayden	4.16	0.02	0.04	0.02	0.19	0.03	0.23
Oxnard	Haydock	4.16	0.05	0.11	0.07	0.76	0.08	0.88
Venida	Hays	12.0	0.35	0.74	0.49	4.06	0.85	5.18
Fremont	Hayward	4.16	0.10	0.16	0.15	1.15	0.16	1.31
Francis	Hazel	12.0	0.52	0.62	0.76	3.81	1.29	4.73
Chestnut	Hazelnut	12.0	0.57	1.02	0.80	4.93	1.22	6.05
Alessandro	Heacock	12.0	0.65	1.26	0.95	6.79	1.29	8.12
Headley P.T.	Headley	2.4	0.00	0.01	0.01	0.04	0.01	0.04
Heartwell P.T.	Heartwell	4.16	0.04	0.02	0.05	0.33	0.12	0.43
Alder	Heather	12.0	0.31	0.57	0.45	3.21	0.69	4.19
Randsburg	Heavy	33.0	0.01	0.02	0.02	0.14	0.02	0.15
Cady	Hector	12.0	0.13	0.29	0.19	1.65	0.25	2.45
Santa Fe Springs	Hedge	12.0	0.48	0.62	0.78	4.07	1.03	4.40
Maxwell	Heers	12.0	0.44	0.67	0.57	3.51	1.30	5.40
Bain	Heftler	12.0	1.10	1.82	1.76	16.01	1.88	19.19
Oasis	Heights	12.0	0.42	0.72	0.62	4.27	0.79	5.50
Oceanview	Heil	12.0	0.86	1.04	1.31	5.86	1.70	6.60
Trophy	Heisman	12.0	0.50	0.64	0.61	3.74	1.43	5.83
Santa Barbara	Helena	4.16	0.15	0.31	0.20	1.44	0.27	1.97
Skylark	Helenka	12.0	0.15	0.49	0.22	2.33	0.27	3.47
Bunker	Helicopter	12.0	0.33	0.69	0.47	3.95	0.71	5.36
Minneola	Helios	12.0	0.26	0.44	0.39	2.71	0.48	3.36
Maywood	Heliotrope	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Nola	Helium	16.0	0.32	0.43	0.50	2.66	0.61	2.88
Ramona	Hellman	4.16	0.07	0.06	0.08	0.63	0.15	0.80
Newmark	Helm	16.0	0.73	1.36	1.07	7.84	1.44	9.01
Firehouse	Helmet	12.0	1.32	2.43	2.15	15.40	2.15	16.79
Mayberry	Hemacinto	12.0	0.49	0.87	0.72	5.03	1.09	6.44
Porterville	Henderson	12.0	0.74	1.03	1.09	5.53	1.38	6.39
Belvedere	Herbert	4.16	0.01	0.02	0.01	0.03	0.03	0.09
Hesperia	Hercules	12.0	0.76	1.08	1.11	5.49	1.74	7.28
Bovine	Hereford	12.0	0.63	0.69	0.92	4.16	1.45	4.96
Redondo	Hermosa	4.16	0.06	0.12	0.06	1.01	0.08	1.24
Bunker	Hero	12.0	0.32	0.41	0.48	3.24	0.61	3.71
Merced	Herring	12.0	0.86	0.98	1.20	4.76	2.44	6.52
Cardiff	Herz	12.0	0.50	0.65	0.76	3.55	1.06	4.01
Hession P.T.	Hession	12.0	0.03	0.08	0.05	0.36	0.07	0.45
Nelson	Hewitt	12.0	0.16	0.31	0.24	1.84	0.30	2.09
Chestnut	Hexnut	12.0	0.52	0.98	0.78	5.65	0.98	6.48
Artesia	Hibbing	4.16	0.04	0.04	0.05	0.39	0.10	0.51
Kempster	Hibiscus	4.16	0.09	0.14	0.12	0.71	0.21	0.94
Madrid	Hickory	4.16	0.00	0.00	-0.02	0.34	-0.01	0.43
Belvedere P.T.	Hicks	4.16	0.12	0.20	0.16	1.20	0.20	1.34

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Granada	Hidalgo	4.16	0.03	0.09	0.03	0.55	0.04	0.78
Black Meadows	Hidden	12.0	0.02	0.05	0.03	0.28	0.03	0.28
Liberty	Higby	12.0	0.55	1.03	0.73	4.34	1.54	6.42
High P.T.	High	4.16	0.07	0.14	0.11	0.66	0.18	0.75
Bloomington	Highball	12.0	0.54	1.04	0.82	5.89	1.10	6.99
Rush	Highcliff	16.0	0.52	0.89	0.71	5.71	0.99	6.87
Diamond Bar	Highnoon	12.0	0.36	0.39	0.44	2.99	0.75	4.02
High School P.T.	Highschool	2.4	0.02	0.05	0.04	0.30	0.04	0.38
Saticoy	Highway	16.0	0.31	0.59	0.32	5.05	0.44	6.01
Inyokern	Highwaysix	12.0	0.35	0.48	0.53	3.28	0.69	4.28
Borrego	Higo	12.0	0.06	0.17	-0.02	2.00	0.05	3.02
Ridgecrest	Hildreth	4.8	0.04	0.07	0.05	0.37	0.09	0.47
Manhattan	Hill	4.16	0.05	-0.12	0.04	0.72	0.07	0.80
La Canada	Hillard	4.16	0.08	0.19	0.09	0.79	0.22	1.42
Thousand Oaks	Hillcrest	16.0	1.45	1.85	2.09	9.09	3.35	11.49
Solemint	Hillfield	16.0	0.31	0.60	0.40	3.41	0.67	4.69
Coffee	Hills	12.0	0.11	0.15	0.16	1.25	0.20	1.39
Victoria	Hillside	16.0	0.23	0.44	0.31	2.22	0.45	2.66
Sangar	Hilltop	4.16	0.02	0.08	-0.03	0.78	-0.01	1.36
Amalia	Hillview	4.16	0.10	0.16	0.15	0.98	0.20	1.13
Beverly	Hilton	16.0	0.68	1.57	0.99	7.74	1.47	10.30
Mira Loma	Himalayas	12.0	0.49	0.85	0.72	5.14	0.95	6.06
Hi Desert	Himo	33.0	0.01	0.01	0.01	0.07	0.01	0.08
Felton	Hindry	4.16	0.02	0.03	0.01	0.43	0.02	0.52
Irvine	Hines	12.0	0.16	0.11	-0.03	2.23	0.21	3.44
Ravendale	Hinshaw	16.0	0.16	0.31	0.22	2.24	0.24	2.62
Brookhurst	Hirsch	12.0	0.67	0.89	0.97	5.40	1.28	6.46
Ivyglen	Hitch	12.0	0.37	0.41	0.44	3.45	1.04	5.31
Cherry	Hoback	12.0	0.20	0.35	0.27	1.67	0.43	2.12
Fruitland	Hobart	16.0	0.54	0.69	0.84	4.19	1.08	4.59
Railroad	Hobo	12.0	0.43	0.78	0.66	4.67	0.76	6.08
Pixley	Hobson	12.0	0.47	0.74	0.74	6.49	0.85	8.09
Archibald	Hofer	12.0	1.14	1.44	1.77	7.89	2.36	9.03
Lafayette	Hogan	12.0	1.12	1.31	1.75	8.28	2.05	8.87
Westgate	Holbrook	4.16	0.14	0.21	0.19	1.12	0.34	1.45
Badillo	Hollenbeck	4.16	0.16	0.20	0.21	1.07	0.49	1.55
Basta	Holloway	4.16	0.06	0.12	0.08	0.86	0.09	1.10
Anita	Holly	4.16	0.11	0.14	0.13	0.67	0.33	1.16
Del Rosa	Hollyvista	12.0	0.30	0.48	0.59	3.27	0.96	4.08
Fairfax	Hollywood	16.0	1.25	1.63	1.93	9.02	2.51	9.75
Calden	Holmes	16.0	0.14	0.28	0.20	1.47	0.26	1.73
Tippecanoe	Holstein	4.16	0.06	0.11	0.09	0.59	0.13	0.71
Concho	Hombre	12.0	0.71	0.91	1.08	4.56	1.61	5.59
State Street	Home	12.0	0.54	0.69	0.85	3.59	1.02	3.79
Cudahy	Homegardens	4.16	0.15	0.23	0.23	1.50	0.27	1.73
Lemon Cove	Homer	12.0	0.10	0.18	0.13	0.84	0.22	1.07
Homewood P.T.	Homewood	4.8	0.01	0.01	0.01	0.05	0.04	0.07
Imperial	Hondo	4.16	0.07	0.10	0.10	0.68	0.14	0.77
El Casco	Honeycrisp	12.0	0.23	0.71	0.37	3.06	0.42	4.31
Bradbury	Honeywell	16.0	0.51	0.79	0.70	4.40	1.17	5.65
Rosemead	Honor	16.0	0.76	1.61	1.12	9.35	1.33	10.69
Gilbert	Hook	12.0	0.34	0.59	0.51	3.80	0.62	4.37
Hook Creek P.T.	Hookcreek	2.4	0.03	0.03	0.04	0.22	0.04	0.25
Newbury	Hooligan	16.0	0.31	0.91	0.18	5.28	0.52	9.16
Naomi	Hooper	4.16	0.14	0.22	0.21	1.34	0.24	1.47
Alhambra	Hoover	4.16	0.01	0.07	0.00	0.37	0.00	0.63
Etiwanda	Hope	12.0	0.32	0.43	0.40	2.35	0.88	3.53
Shawnee	Hopi	12.0	0.65	0.80	1.02	6.38	1.17	7.25
Bloomington	Hopper	12.0	0.27	0.35	0.40	2.83	0.47	3.09
Valdez	Horizon	16.0	0.78	1.47	1.08	6.49	2.07	9.40
Silver Spur	Horn	12.0	0.29	0.29	0.45	2.84	0.47	2.86
Valdez	Horntoad	16.0	0.80	1.35	1.00	5.32	2.36	9.11
Estrella	Horoscope	12.0	0.20	0.47	0.11	4.98	0.21	6.61
Bird Springs P.T.	Horsemountain	2.4	0.00	0.00	0.00	0.01	0.00	0.01
Canyon	Horseshoe	12.0	0.45	0.91	0.56	4.73	1.05	7.00
Fogarty	Horton	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Firehouse	Hose	12.0	0.57	0.84	0.89	5.22	1.10	5.80
Del Rosa	Hospat	12.0	2.43	3.88	7.66	18.19	18.92	34.35
Pierpont	Hospital	4.16	0.06	0.05	0.07	0.79	0.12	1.05

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Royal	Hoss	16.0	1.01	0.94	1.20	5.04	3.66	9.09
Hossack P.T.	Hossack	2.4	0.01	0.01	0.01	0.05	0.01	0.05
Upland	Hotpoint	12.0	0.08	0.20	0.11	0.67	0.21	1.12
Santa Barbara	Hotsprings	16.0	1.16	1.78	1.69	10.17	2.11	12.08
Hot Water P.T.	Hotwater	12.0	0.01	0.02	0.01	0.12	0.02	0.13
Pioneer	Houghton	4.16	0.03	0.05	0.04	0.42	0.04	0.48
Poplar	Houston	12.0	0.31	0.45	0.46	3.32	0.57	3.92
Del Rosa	Hovatter	12.0	0.67	0.94	0.92	4.28	2.07	6.04
Redman	Hovey	12.0	0.08	0.13	0.13	1.15	0.15	1.62
Verdant	Howbuck	12.0	0.04	0.06	0.06	0.29	0.09	0.38
Eisenhower	Howitzer	12.0	0.51	0.63	0.76	3.06	1.18	3.82
Devers	Hubble	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Fremont	Hubcity	16.0	0.29	0.40	0.51	2.55	0.78	3.01
Ritter Ranch	Huckleberry	12.0	0.04	0.11	0.05	0.37	0.06	0.58
Bryan	Hudson	12.0	0.49	0.74	0.73	4.11	1.10	4.85
Tortilla	Huevos	12.0	0.50	0.97	0.73	4.84	1.02	5.96
Alder	Huff	12.0	0.47	0.89	0.67	4.99	0.94	6.25
Del Sur	Hugheslake	12.0	0.38	0.48	0.69	3.10	1.16	4.32
Murrietta	Hugo	12.0	0.11	0.23	0.18	1.49	0.19	1.52
Inyokern	Hulsey	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Dryden P.T.	Hulstein	12.0	0.27	0.73	0.36	2.98	0.59	4.08
Moraga	Humber	12.0	0.36	0.72	0.51	3.84	0.75	5.04
Wave	Humble	12.0	0.48	1.04	0.71	5.96	0.81	6.57
Bicknell	Humphrey	4.16	0.10	0.16	0.16	1.13	0.16	1.16
Fullerton	Hunt	12.0	0.60	1.07	0.86	5.62	1.30	6.81
Moraga	Hunter	12.0	0.34	0.66	0.51	3.51	0.65	3.91
Casa Diablo	Hurley	12.0	0.07	0.30	0.11	1.44	0.13	1.78
Great Lakes	Huron	12.0	0.45	0.63	0.66	3.63	0.93	4.33
Yorba Linda	Hurricane	12.0	0.48	0.67	0.62	3.59	1.35	5.22
San Marcos	Hurst	16.0	0.30	0.27	0.21	4.74	0.38	5.09
Bradbury	Hurstview	16.0	0.77	1.26	1.16	8.00	1.46	8.92
Moulton	Huskie	12.0	0.54	0.99	0.79	5.98	1.00	6.82
Highland	Hutchins	12.0	0.22	0.54	0.27	2.39	0.60	4.11
Hutt P.T.	Hutt	12.0	0.00	0.00	0.00	0.01	0.01	0.02
Inglewood	Hydepark	4.16	0.13	0.18	0.20	1.19	0.23	1.32
Firehouse	Hydrant	12.0	1.78	2.41	4.56	13.62	9.70	21.74
Greening	Ibex	12.0	0.82	0.83	1.23	6.48	1.68	7.47
Ice House P.T.	Icehouse	2.4	0.00	0.00	0.00	0.00	0.00	0.00
Maraschino	Ida	12.0	0.50	0.83	0.72	6.51	0.85	7.41
La Habra	Idaho	12.0	0.48	0.89	0.69	4.63	0.99	5.64
Idyllbrook P.T.	Idyllbrook	2.4	0.03	0.08	0.04	0.41	0.04	0.50
Eisenhower	Ike	12.0	0.58	0.74	0.90	3.89	1.23	4.54
Moneta	Illinois	4.16	0.08	0.06	0.05	1.10	0.09	1.33
Archibald	Imbach	12.0	0.38	0.60	0.53	3.29	1.01	4.57
Indian Wells	Inca	12.0	0.31	0.49	0.44	1.92	0.83	2.86
Palm Village	Inch	12.0	0.56	0.77	0.87	4.93	0.93	5.05
Peyton	Independence	12.0	0.37	0.47	0.44	2.88	1.13	4.69
Belvedere	Indiana	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Trask	Indianapolis	12.0	0.86	1.18	1.25	6.26	1.71	7.53
Firehouse	Inferno	12.0	0.42	0.66	0.64	4.49	0.82	5.28
Paularino	Inlet	4.16	0.04	0.28	0.02	1.29	0.03	2.22
Baker	Inn	12.0	0.13	0.29	0.20	1.55	0.24	1.63
Kernville	Intake	12.0	0.05	0.07	0.06	0.32	0.08	0.39
Timoteo	Intern	12.0	0.36	0.76	0.46	4.07	0.81	5.83
Roadway	International	12.0	0.62	0.80	0.89	3.67	1.81	5.27
Corona	Interpace	33.0	0.00	0.01	0.01	0.04	0.01	0.05
Sepulveda	Interstate	16.0	0.42	0.54	0.65	3.59	0.81	3.95
Newbury	Intrepid	16.0	0.39	0.79	0.34	6.21	0.58	9.09
Devers	Invader	12.0	0.36	0.79	0.56	5.44	0.61	7.26
Quartz Hill	Invention	12.0	0.48	0.77	0.57	3.53	1.40	5.99
Mt. Tom	Inyolumber	12.0	0.85	1.05	1.20	5.74	1.69	7.53
Hanford	Iona	12.0	0.64	1.08	0.89	6.11	1.38	7.23
Somerset	Iowa	4.16	0.21	0.22	0.29	1.33	0.55	1.68
Gage	Ira	4.16	0.16	0.22	0.25	1.54	0.27	1.60
Modena	Iran	12.0	0.21	0.77	0.26	3.75	0.36	5.94
Lark Ellen	Irene	12.0	0.08	0.11	0.09	0.30	0.19	0.52
Arch Beach	Iris	4.16	0.00	0.00	-0.01	0.03	-0.01	0.06
Lighthipe	Irish	12.0	0.29	0.72	0.44	4.49	0.51	4.77
Limestone	Iron	12.0	0.39	0.74	0.60	4.28	0.73	4.56

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Bloomington	Ironhorse	12.0	0.49	0.96	0.76	5.96	0.91	6.57
IronPrison P.T.	Ironprison	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Santa Rosa	Irontree	12.0	0.46	0.95	0.69	3.98	1.02	5.80
Alessandro	Ironwood	33.0	0.49	0.63	0.80	3.72	0.80	3.82
Irvine Park P.T.	Irvinepark	2.4	0.00	0.01	0.00	0.19	0.00	0.39
Shandin	Irvington	12.0	0.32	0.57	0.45	2.72	0.78	3.70
Hanford	Irwin	4.16	0.18	0.22	0.32	1.08	0.54	1.33
Santa Monica	Irwinhts	4.16	0.13	0.21	0.20	1.18	0.29	1.36
Proctor	Isis	12.0	0.77	1.05	1.18	7.34	1.58	9.49
Kramer	Isner	33.0	0.03	0.04	0.04	0.28	0.04	0.29
Modena	Israel	12.0	0.14	0.73	0.07	4.04	0.18	6.92
Monrovia	Ivy	4.16	0.07	0.11	0.10	0.58	0.20	0.81
Tamarisk	Jacaranda	12.0	0.70	1.01	1.06	5.01	1.56	6.43
Lancaster	Jackman	12.0	0.51	0.89	0.75	4.56	1.02	5.92
Jackpot P.T	Jackpot	25.0	0.00	0.00	0.00	0.00	0.00	0.00
Beaumont	Jackrabbit	4.16	0.04	0.06	0.09	0.51	0.18	0.83
Downs	Jackranch	12.0	0.33	0.45	0.53	3.39	0.64	4.37
Culver	Jackson	16.0	0.24	0.56	0.37	3.02	0.44	3.17
Friendly Hills	Jacmar	4.16	0.08	0.07	0.11	0.62	0.21	0.78
Marion	Jacque	12.0	0.24	0.59	0.26	4.36	0.34	5.69
Crown	Jade	12.0	0.33	1.03	0.39	5.29	0.48	7.70
Lampson	Jaguar	12.0	0.16	0.39	0.25	2.45	0.26	2.49
Smiley	Jake	4.16	0.05	0.10	0.04	0.57	0.13	1.04
Ely	Jamaica	12.0	0.58	1.01	0.83	6.00	1.16	7.46
Crown	Jamboree	12.0	0.17	0.76	0.10	3.91	0.25	6.64
Imperial	James	4.16	0.09	0.10	0.12	0.88	0.19	1.06
Santa Barbara	Jameson	16.0	0.68	1.53	0.97	8.63	1.19	9.40
Carmenita	Janae	12.0	0.61	0.74	0.88	4.20	1.60	5.43
Ditmar	Janice	4.16	0.08	0.09	0.10	0.85	0.13	1.00
Moorpark	Janss	16.0	0.40	0.63	0.30	5.20	0.96	8.38
Lafayette	January	12.0	0.59	1.29	0.83	6.76	0.96	8.68
Dalton	Jarvis	12.0	0.87	1.16	1.34	7.75	1.82	10.40
Quinn	Jasmine	12.0	0.34	0.44	0.51	2.88	0.72	3.72
Redlands	Jasper	12.0	0.26	0.51	0.31	3.06	0.58	4.45
Lennox	Java	4.16	0.06	0.11	0.09	0.63	0.11	0.70
Cantil	Jawbone	12.0	0.03	0.04	0.04	0.13	0.09	0.18
Universal	Jaws	12.0	0.44	0.56	0.71	3.22	0.73	3.25
Jay P.T.	Jay	4.16	0.05	0.09	0.06	0.71	0.07	0.84
Archline	Jaybird	12.0	0.44	0.86	0.64	4.64	0.98	6.06
Passons	Jayblue	12.0	0.66	0.72	1.04	6.82	1.18	8.56
Basta	Jaymac	4.16	0.04	0.13	0.05	0.86	0.05	1.20
Team	Jazz	12.0	0.91	1.04	1.35	6.69	2.05	7.86
Saugus	Jbsherman	16.0	0.34	0.81	0.47	4.64	0.51	6.23
Shuttle	Jedi	12.0	0.74	1.11	1.08	5.60	1.62	7.35
Arrowhead	Jeep	12.0	0.30	0.70	0.43	3.08	0.56	4.12
Irvine	Jeffrey	12.0	0.38	0.68	0.50	4.91	0.67	5.79
Yucca	Jellystone	12.0	0.44	0.84	0.59	4.17	0.96	6.44
Carson	Jenkins	16.0	1.16	1.45	1.80	9.77	2.33	11.75
Converse Flats	Jenkslake	12.0	0.03	0.06	0.05	0.35	0.06	0.37
Los Cerritos	Jennings	12.0	0.87	1.12	1.32	6.21	1.69	6.76
Lucas	Jepson	12.0	0.62	1.08	0.95	6.90	1.15	7.55
Trask	Jerome	12.0	1.09	1.30	1.62	7.08	2.17	8.07
Valley	Jerry	12.0	0.11	0.25	0.17	1.34	0.25	1.87
Tenaja	Jerusalem	12.0	0.19	0.29	0.29	2.61	0.30	2.84
Apple Valley	Jess	12.0	0.55	0.78	0.74	3.56	1.51	5.44
Jessie P.T.	Jessie	4.16	0.02	0.04	0.03	0.20	0.03	0.26
Floraday	Jessup	4.16	0.12	0.18	0.17	1.12	0.30	1.46
Parker Strip	Jetski	12.0	0.16	0.24	0.29	1.44	0.39	1.56
Stewart	Jimmy	12.0	1.93	2.54	2.99	14.69	3.87	16.64
Mentone	Jims	12.0	0.15	0.41	0.19	2.36	0.25	3.36
Fairview	Joaquin	12.0	0.54	1.13	0.80	5.97	1.06	6.66
Job P.T.	Job	2.4	0.03	0.09	0.04	0.38	0.05	0.51
Joburg P.T.	Joburg	2.4	0.03	0.07	0.04	0.27	0.07	0.34
Fullerton	Joclyn	4.16	0.00	0.02	0.00	0.04	0.00	0.07
Moneta	Johanna	4.16	0.08	0.12	0.12	0.80	0.14	0.91
Newbury	Johnboy	16.0	1.56	1.96	4.25	11.74	9.92	20.08
Johnsondale P.T.	Johnsondale	4.16	0.02	0.03	0.03	0.14	0.04	0.17
Cortez	Jojo	12.0	0.21	0.26	0.31	1.33	0.42	1.53
El Casco	Jonagold	12.0	0.21	0.46	0.31	2.24	0.44	2.83

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Ocean Park	Jones	4.16	0.08	0.06	0.04	0.67	0.12	0.98
Trask	Joplin	12.0	0.89	1.03	1.30	6.44	1.88	7.70
Glennville	Jordan	12.0	0.23	0.42	0.30	1.45	0.47	2.15
Ravendale	Josard	16.0	0.10	0.44	0.02	2.78	0.12	4.65
Lancaster	Joshua	12.0	0.56	0.85	0.81	4.09	1.08	4.92
Clark	Josie	4.16	0.05	0.09	0.01	1.05	0.03	1.54
Bandini	Joslyn	16.0	1.09	1.46	1.69	9.05	2.11	10.24
Porterville	Josten	12.0	0.73	0.98	1.07	4.82	1.59	5.94
Corona	Joy	4.16	0.03	0.05	0.05	0.30	0.08	0.38
Arcadia	Joyce	4.16	0.09	0.17	0.13	1.04	0.20	1.38
Brea	Juarez	12.0	0.42	0.80	0.57	4.54	0.90	5.99
Maraschino	Jubilee	12.0	0.21	0.44	0.29	2.35	0.46	3.31
Felton	Judah	4.16	0.01	-0.05	-0.05	0.60	-0.04	0.76
Cornuta	Judge	12.0	0.51	0.68	0.75	3.23	1.10	3.75
Redlands	Judson	12.0	0.36	0.68	0.50	4.16	0.74	5.38
Ordway	Judy	12.0	0.28	0.59	0.42	3.04	0.50	3.57
Narrows	Julep	12.0	0.04	0.06	0.05	0.41	0.07	0.49
Haskell	Julius	16.0	0.23	0.71	0.29	3.55	0.40	5.39
Yukon	Juneau	4.16	0.08	0.12	0.12	0.77	0.17	0.90
Randall	Junior	12.0	0.54	0.99	0.76	5.69	1.08	7.00
Nuevo	Juniper	12.0	0.81	1.28	2.42	8.28	5.80	15.60
Bluff Cove	Jupiter	4.16	0.00	0.11	-0.06	0.97	-0.05	1.60
Narod	Jurupa	12.0	0.45	0.68	0.62	3.63	1.13	4.86
Cornuta	Jury	12.0	0.84	1.14	1.21	5.64	2.01	6.97
Cardiff	Justice	12.0	0.89	1.17	1.42	6.73	1.57	7.18
Mayberry	Kadice	12.0	0.33	0.69	0.46	3.77	0.74	5.31
Francis	Kadota	12.0	0.91	1.07	1.30	5.42	2.28	6.98
Chiquita	Kahlua	12.0	0.34	0.83	0.42	4.61	0.59	6.25
Declez	Kaiser	12.0	0.91	0.99	1.25	5.53	2.58	7.94
San Fernando	Kalisher	16.0	0.90	1.03	1.40	5.88	2.10	6.32
Calden	Kalmia	16.0	0.41	0.74	0.60	4.39	0.72	5.03
Malibu	Kanan	16.0	0.56	0.58	0.61	3.95	1.81	6.80
Pearl	Kansas	4.16	0.07	0.10	0.03	1.13	0.07	1.55
Telegraph	Kappa	12.0	0.12	0.14	0.16	1.04	0.24	1.23
Marion	Karen	12.0	0.37	0.89	0.50	5.49	0.59	6.78
Victorville	Kasota	12.0	1.07	1.26	1.56	6.01	2.39	7.53
Cypress	Katella	12.0	0.76	0.92	1.16	6.15	1.45	7.00
Harding	Katherine	4.16	0.13	0.13	0.18	0.96	0.33	1.21
Felton	Kathleen	16.0	0.57	0.68	0.90	4.04	1.08	4.37
Anita	Kauffman	4.16	0.03	0.05	0.04	0.41	0.07	0.59
Alhambra	Kay	16.0	0.63	1.05	0.86	6.49	1.24	7.85
Kearney P.T.	Kearney	2.4	0.01	0.02	0.02	0.08	0.04	0.12
Manhattan	Keats	4.16	0.00	-0.02	-0.01	0.12	0.01	0.42
Quartz Hill	Keefer	12.0	0.28	0.74	0.39	2.69	0.61	4.05
Pico	Keel	12.0	0.26	0.35	0.42	2.28	0.44	2.67
Irvine	Keeline	12.0	0.51	0.98	0.77	5.43	0.94	5.76
Monolith	Keene	12.0	0.07	0.10	0.10	0.51	0.17	0.67
Sunnyside	Keever	4.16	0.12	0.21	0.17	1.45	0.20	1.76
Garvey	Keim	4.16	0.06	0.06	0.08	0.60	0.13	0.75
Westgate	Keith	4.16	0.05	0.09	0.05	0.71	0.07	0.91
Lighthipe	Kelber	12.0	0.99	1.27	1.53	7.75	2.00	8.38
Auld	Keller	12.0	0.17	0.52	0.16	3.18	0.28	4.98
La Mirada	Kelsey	12.0	0.46	0.45	0.64	2.81	1.16	3.58
Cabrillo	Kelvin	12.0	0.31	0.68	0.48	4.14	0.50	4.61
Sepulveda	Kelvinator	16.0	0.99	1.42	1.53	8.41	1.94	9.34
Repetto	Kenbo	4.16	0.04	0.01	0.04	0.41	0.12	0.61
Stoddard	Kendell	4.16	0.06	0.12	0.09	0.62	0.13	0.72
Newmark	Kenmore	4.16	0.07	0.05	0.08	0.65	0.19	0.95
Inyokern	Kennedy	33.0	0.00	0.00	0.00	0.01	0.00	0.01
Floraday	Kenney	4.16	0.09	0.10	0.12	0.93	0.20	1.15
Phelan	Keno	12.0	0.47	1.09	0.67	5.05	0.79	7.61
Pomona	Kenoak	4.16	0.11	0.14	0.15	0.69	0.31	0.96
Carolina	Kentucky	12.0	0.32	0.55	0.45	3.06	0.72	3.87
Bullis	Kenwood	16.0	0.62	0.80	0.94	4.05	1.38	4.78
Roadway	Kenworth	12.0	0.45	0.75	0.68	4.39	0.80	5.45
Archline	Kenyon	12.0	0.44	0.85	0.64	4.57	0.86	5.46
Nogales	Kermit	12.0	0.35	0.43	0.44	3.00	0.95	4.40
Hesperia	Kern	12.0	1.16	1.36	1.68	6.35	2.85	8.26
Jersey	Kernan	16.0	1.79	2.47	4.48	13.52	9.68	21.79

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Fogarty	Kerry	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Milliken	Kessler	12.0	1.29	1.62	2.04	9.64	2.30	10.48
Bolsa	Ketch	12.0	1.09	1.29	1.63	8.05	2.58	9.67
Crown	Kewamee	12.0	0.38	1.32	0.47	6.60	0.55	9.29
San Marino	Kewen	4.16	0.07	0.19	0.09	0.85	0.14	1.19
Neptune	Keystone	4.16	0.14	0.20	0.20	1.59	0.28	1.83
Washington	Kick	12.0	0.95	1.12	1.37	4.58	2.29	5.71
Yucca	Kickapootrail	12.0	0.66	0.79	1.16	5.23	1.79	6.82
Cameron	Kidd	12.0	0.28	0.36	0.44	2.09	0.48	2.24
Arcadia	Kieway	16.0	0.53	1.00	0.79	5.54	1.03	6.16
Murphy	Kilkenny	12.0	1.03	1.05	1.38	5.38	3.05	8.02
Sunnyside	Killdee	4.16	0.12	0.22	0.16	1.56	0.19	1.83
Murphy	Kilroy	12.0	0.75	0.92	1.11	4.61	1.75	5.53
Highland	Kilts	12.0	0.57	0.79	0.76	4.78	1.52	6.73
Kimberly P.T.	Kimberly	2.4	0.01	0.02	0.02	0.11	0.04	0.14
Cajalco	Kimdale	12.0	0.74	0.79	1.00	4.29	2.36	6.39
Victoria	King	16.0	0.57	1.02	0.73	6.36	0.92	7.67
Kimball	Kingcobra	12.0	0.15	0.32	0.24	1.77	0.25	2.12
Ravendale	Kinghurst	4.16	0.13	0.15	0.15	0.75	0.40	1.32
Hanford	Kings	4.16	0.01	0.02	0.01	0.03	0.04	0.08
Corona	Kingsford	12.0	0.27	0.51	0.35	2.46	0.74	3.93
San Antonio	Kingsley	12.0	0.41	0.71	0.58	4.39	0.77	5.01
Alessandro	Kingsway	12.0	0.34	0.62	0.49	3.51	0.73	4.33
Lancaster	Kingtree	12.0	0.47	0.68	0.70	3.90	0.97	4.75
Laguna Bell	Kinmont	16.0	0.32	0.42	0.50	2.76	0.59	2.86
Eaton	Kinneloa	16.0	0.23	0.64	0.19	4.15	0.35	6.02
Gorman	Kinsey	12.0	0.08	0.10	0.12	0.55	0.18	0.64
Apple Valley	Kiowa	12.0	0.81	1.04	1.19	5.02	1.90	6.14
Nelson	Kirby	12.0	0.66	1.12	0.95	6.02	1.39	7.25
Exeter	Kirk	4.16	0.01	0.01	0.01	0.02	0.02	0.04
Griswold	Kittridge	4.16	0.00	0.05	-0.01	0.04	0.01	0.28
Fogarty	Kleven	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Gisler	Klingon	12.0	0.67	0.99	1.03	5.71	1.28	6.31
Kliss P.T.	Kliss	4.16	0.01	0.03	0.01	0.26	0.01	0.35
Upland	Klusman	4.16	0.10	0.17	0.15	0.96	0.24	1.21
Kneeland P.T.	Kneeland	4.16	0.03	0.04	0.04	0.31	0.06	0.39
Rancho	Knolls	12.0	0.72	0.88	1.05	4.12	1.69	5.34
La Palma	Knott	12.0	0.60	1.05	0.89	5.71	1.20	6.34
Griswold	Knox	4.16	0.09	0.12	0.12	0.83	0.17	1.02
Victor	Koala	12.0	0.51	0.56	0.74	3.56	1.22	4.65
Fruitland	Kobe	16.0	0.53	0.66	0.79	3.09	1.20	3.68
Koefler P.T.	Koefler	4.8	0.00	0.00	0.00	0.01	0.00	0.02
Coffee	Kona	12.0	0.58	0.91	0.90	5.77	0.96	6.72
Shuttle	Konobie	12.0	0.45	0.82	0.55	3.64	1.38	6.51
Stewart	Kordell	12.0	0.38	0.43	0.56	2.64	0.92	3.21
Modena	Korea	12.0	0.16	0.83	0.09	4.03	0.23	7.21
Lawndale	Kornblum	4.16	0.10	0.12	0.13	0.95	0.16	1.08
Glen Avon	Kraft	12.0	0.44	0.80	0.63	4.02	1.01	5.15
San Dimas	Kranzer	12.0	0.08	0.28	0.10	1.29	0.11	1.94
Ripley	Kratka	12.0	0.09	0.12	0.12	0.49	0.23	0.69
Marion	Kristen	12.0	0.42	0.78	0.65	5.00	0.76	5.49
Santiago	Krona	12.0	0.15	0.19	0.06	3.13	0.13	4.21
Archibald	Kropp	12.0	0.47	0.47	0.54	3.89	1.34	5.97
MacArthur	Krueger	12.0	0.27	0.92	0.38	3.95	0.42	6.16
Limestone	Krypton	12.0	0.65	1.00	1.03	7.33	1.13	7.64
Santa Susana	Kuehner	16.0	0.62	0.95	0.85	5.25	1.33	6.90
Kuffel P.T.	Kuffel	2.4	0.03	0.08	0.05	0.42	0.05	0.49
Murrietta	Kulberg	12.0	0.32	0.68	0.39	3.51	0.77	5.27
Citrus	Kumquat	12.0	0.65	0.85	0.96	4.66	1.45	5.82
Santiago	Kuna	12.0	0.37	0.56	0.50	3.75	0.76	4.61
Hanford	Kutner	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Santiago	Kwacha	12.0	0.28	0.57	0.43	3.28	0.52	3.59
Walnut	Kwis	12.0	0.52	0.71	0.67	3.92	1.38	6.32
Quinn	Kyte	12.0	0.34	0.49	0.51	3.36	0.68	4.27
Pedley	Lab	12.0	0.32	0.49	0.48	3.73	0.52	3.97
Fairfax	Labrea	4.16	0.14	0.18	0.24	1.08	0.35	1.28
Lacresta P.T.	Lacresta	12.0	0.09	0.32	0.11	1.34	0.13	2.18
La Cumbre P.T.	Lacumbre	4.16	0.12	0.16	0.17	1.08	0.23	1.71
Firehouse	Ladder	12.0	0.33	0.44	0.50	2.80	0.70	3.31

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Windsor Hills	Ladera	4.16	0.06	0.15	0.07	0.91	0.09	1.25
Dalton	Lager	12.0	0.34	0.42	0.54	3.45	0.63	4.05
Blythe City	Lagoon	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Archline	Lagrande	12.0	0.31	0.50	0.52	4.64	0.66	7.70
Santa Fe Springs	Laird	12.0	1.13	1.22	1.60	6.17	2.91	7.74
Fair Oaks	Lake	4.16	0.12	0.07	0.14	0.68	0.28	0.88
Elsinore	Lakeland	12.0	0.22	0.60	0.31	2.96	0.39	4.13
Team	Lakers	12.0	0.88	0.98	1.33	6.26	1.77	7.18
Rancho	Lakota	12.0	1.14	1.38	1.69	7.04	2.64	9.06
Potrero	Lamancha	16.0	0.47	0.72	1.30	6.48	2.96	10.45
Eaton	Lamanda	16.0	0.04	0.13	0.00	1.12	0.03	1.74
Pepper	Lancers	12.0	0.46	0.90	0.67	4.89	0.94	6.17
Farrell	Landau	12.0	0.59	0.93	0.85	4.04	1.58	6.03
Nugget	Landers	25.0	0.30	0.37	0.46	2.74	0.49	2.93
Alessandro	Landmark	12.0	0.63	1.15	0.96	5.92	1.36	7.01
La Canada	Lane	4.16	0.04	0.01	0.05	0.45	0.05	0.46
Thousand Oaks	Langer	16.0	0.27	0.63	0.25	3.22	0.48	5.19
Ellis	Langley	12.0	0.87	1.03	1.11	6.63	2.16	8.90
Fremont	Lantana	16.0	0.18	0.36	0.25	1.99	0.35	2.50
Sharon	Lanterman	4.16	0.26	0.49	0.30	1.12	1.08	2.96
Mariposa	Lanza	12.0	0.23	0.32	0.32	1.61	0.45	1.94
Victorville	Lapaz	12.0	1.13	1.35	1.84	7.90	2.06	8.45
Beverly	Lapeer	16.0	0.72	1.59	1.16	9.30	1.30	9.70
Maraschino	Lapins	12.0	0.33	0.76	0.51	4.76	0.55	6.06
Anita	Laporte	16.0	0.58	0.94	0.98	6.53	1.40	8.04
Redlands	Laposada	4.16	0.09	0.13	0.14	0.91	0.21	1.19
San Gabriel	Lapresa	4.16	0.12	0.19	0.18	1.23	0.22	1.53
Santa Rosa	Laquinta	33.0	0.48	0.59	0.77	3.42	0.78	3.43
Fairfax	Larabee	16.0	1.21	1.54	1.89	8.96	2.24	9.66
Calectric	Larch	33.0	0.53	1.77	0.85	12.34	0.86	15.15
Imperial	Laredo	12.0	0.66	0.80	1.00	4.57	1.46	5.40
Quartz Hill	Lariat	12.0	0.57	0.86	0.77	3.62	1.39	5.21
Dalton	Larica	12.0	0.01	0.01	0.01	0.02	0.02	0.04
Wrightwood	Lark	2.4	0.04	0.12	0.06	0.64	0.08	0.80
Carodean	Larrea	12.0	0.56	0.90	0.80	4.38	1.12	5.82
Somerset	Larry	12.0	0.51	0.65	0.75	3.52	1.06	4.16
Bryan	Larthien	12.0	0.47	0.75	0.71	4.25	0.89	4.68
Cabrillo	Lasalle	12.0	0.34	0.78	0.54	4.55	0.58	4.74
Pedley	Lasierra	12.0	0.17	0.24	0.27	1.28	0.43	1.59
Palmdale	Lasker	12.0	0.35	0.51	0.46	3.04	0.87	4.43
Olympic	Lasky	4.16	0.08	0.16	0.10	0.65	0.25	1.20
Holiday	Laspalmas	4.16	0.09	0.11	0.23	1.06	0.47	1.70
Victorville	Laspiedras	4.16	0.03	0.05	0.08	0.43	0.17	0.74
Santa Monica	Lassen	4.16	0.04	0.07	0.06	0.40	0.07	0.44
Jefferson	Last	12.0	0.20	0.23	0.28	2.68	0.30	2.89
San Gabriel	Lastunas	4.16	0.09	0.14	0.14	1.69	0.17	4.21
Randolph	Latchford	16.0	0.58	0.76	0.91	4.74	1.09	5.34
Industry	Lathe	12.0	2.44	3.37	6.73	18.49	15.08	31.50
Victor	Latimer	12.0	0.71	0.79	0.99	4.02	2.02	5.79
Repetto	Latin	4.16	0.12	0.15	0.16	0.75	0.29	0.95
Hanford	Laton	12.0	0.43	0.96	0.56	4.19	1.29	6.34
Coffee	Latte	12.0	0.00	0.00	0.00	-0.01	0.00	0.00
Nelson	Lauda	33.0	0.04	0.06	0.06	0.45	0.06	0.45
Bolsa	Launch	12.0	0.30	0.61	0.31	4.51	0.39	6.25
Modoc	Lauro	4.16	0.05	0.06	0.05	0.56	0.11	0.95
West Barstow	Lauterbach	4.16	0.07	0.11	0.10	0.50	0.18	0.68
Amboy	Lava	12.0	0.02	0.04	0.03	0.11	0.05	0.17
Potrero	Lavaca	16.0	0.57	0.73	1.13	4.54	1.90	5.57
Wimbledon	Laver	12.0	0.43	1.22	0.70	8.01	0.70	9.28
Diamond Bar	Lawman	12.0	0.69	0.77	0.90	4.38	2.06	6.15
Fullerton	Lawrence	12.0	0.34	0.60	0.48	2.87	0.72	3.33
Stadium	Laws	12.0	0.37	0.71	0.54	4.53	0.65	5.15
Puente	Lawson	12.0	0.61	0.92	0.98	7.13	1.01	9.00
Porter	Lazard	4.16	-0.01	0.01	-0.02	-0.02	-0.01	0.10
Pechanga	Lazaro	12.0	0.21	0.58	0.16	2.44	0.67	5.13
Limestone	Lead	12.0	0.47	0.84	0.70	4.68	0.88	5.05
Dunes	Leak	12.0	0.14	0.28	0.21	1.29	0.24	1.67
Stetson	Lear	12.0	0.33	0.42	0.46	2.74	0.91	3.53
Mt. Vernon	Leber	4.16	0.05	0.08	0.08	0.61	0.09	0.62

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Borrego	Leche	12.0	0.56	1.00	0.85	6.16	1.07	6.89
Palmdale	Ledford	12.0	0.69	0.98	1.04	5.64	1.51	7.02
Locust	Lee	4.16	0.16	0.23	0.21	1.14	0.33	1.33
Bassett	Leetum	12.0	0.93	1.14	1.42	7.28	1.76	8.22
Santa Fe Springs	Leffingwell	12.0	0.71	1.03	0.99	5.43	1.66	6.72
Ventura	Legion	4.16	0.03	0.06	0.04	0.34	0.06	0.38
San Antonio	Lehigh	12.0	0.44	0.76	0.60	4.81	0.88	5.83
Shuttle	Leia	12.0	0.38	0.80	0.50	3.34	0.87	5.37
Locust	Lemon	4.16	0.10	0.15	0.14	1.04	0.16	1.10
Citrus	Lemonade	12.0	0.76	0.94	0.97	3.95	2.68	6.76
Carmenita	Lemont	12.0	0.46	0.68	0.73	5.22	0.84	5.99
Hanford	Lemoore	12.0	0.77	1.15	1.13	5.80	1.76	7.47
Cardiff	Lena	12.0	0.83	1.11	1.26	6.38	1.54	7.17
Rector	Leo	12.0	0.24	0.46	0.35	3.17	0.44	3.51
Auld	Leon	12.0	0.27	0.73	0.30	2.89	0.78	5.43
Anaverde	Leona	12.0	0.22	0.38	0.25	2.06	0.46	3.13
Amalia	Leonard	4.16	0.08	0.13	0.12	0.76	0.16	0.87
Lampson	Leopard	12.0	0.70	1.28	0.98	7.46	1.34	8.68
Fruitland	Leota	16.0	0.21	0.37	0.31	2.15	0.42	2.44
Valencia	Leroy	4.16	0.13	0.20	0.19	1.06	0.35	1.35
Bedford	Leslie	4.16	0.13	0.24	0.18	1.09	0.31	1.46
Newbury	Lesser	16.0	1.46	1.65	2.31	12.35	2.66	13.01
Jefferson	Lester	12.0	0.47	0.62	0.59	3.87	1.38	5.92
Blythe City	Lettuce	12.0	0.60	0.79	0.85	3.27	1.36	4.13
Monolith	Leveche	12.0	0.34	0.49	0.46	2.70	0.68	3.43
Industry	Level	12.0	0.69	0.82	1.05	6.00	1.23	6.58
Lindsay	Lewis	12.0	0.35	0.62	0.46	3.54	0.70	4.58
Pierpont	Lexington	4.16	0.02	0.04	0.02	0.35	0.03	0.45
Sepulveda	Liberator	16.0	1.16	1.75	1.88	10.79	1.92	11.44
Cudahy	Liberty	4.16	0.10	0.14	0.14	1.11	0.16	1.27
Repetto	Libra	16.0	0.53	0.97	0.81	5.95	0.95	6.51
Inglewood	Lidums	4.16	0.10	0.18	0.14	1.28	0.15	1.43
North Intake	Lift	12.0	0.02	0.02	0.03	0.17	0.03	0.18
Rolling Hills	Lilac	4.16	0.01	0.07	0.01	0.60	0.02	1.05
Daisy	Lily	4.16	0.11	0.19	0.15	0.98	0.20	1.11
Sierra Madre	Lima	4.16	0.23	0.21	0.28	0.89	0.70	1.48
Live Oak	Limber	12.0	0.61	0.90	0.74	3.89	2.06	6.90
Locust	Lime	4.16	0.24	0.37	0.33	1.83	0.46	2.11
Layfair	Liming	12.0	0.65	0.98	0.95	5.53	1.64	6.72
Elsinore	Limited	12.0	0.38	0.70	0.55	3.94	0.75	4.75
Calectric	Limonite	33.0	0.06	0.27	0.10	5.69	0.10	10.92
Visalia	Lincoln	4.16	0.10	0.18	0.14	0.81	0.25	0.96
Garnet	Lindavista	12.0	0.31	0.37	0.63	2.84	1.13	4.10
Stetson	Lindberg	12.0	0.51	0.91	0.75	5.13	0.99	5.83
Laurel	Linder	12.0	0.46	0.65	0.67	4.46	0.84	5.50
Malibu	Lindero	16.0	0.49	0.97	0.57	4.08	1.59	7.73
Stadler	Linebacker	12.0	0.33	0.67	0.49	3.73	0.62	4.28
Rector	Linnell	12.0	0.61	0.84	0.86	4.03	1.36	5.24
Wrightwood	Linnet	2.4	0.04	0.10	0.06	0.57	0.06	0.70
Santiago	Lire	12.0	0.58	0.96	0.86	6.03	1.11	6.89
La Veta	Lisaanne	12.0	0.38	0.61	0.79	4.50	1.46	6.45
Bryan	Lisbon	12.0	0.36	0.65	0.50	3.12	0.78	4.11
Chase	Liston	12.0	0.50	0.96	0.73	5.39	0.99	6.56
Limestone	Lithium	12.0	0.32	0.53	0.48	3.36	0.59	3.67
Valencia	Litra	4.16	0.09	0.11	0.12	0.67	0.25	0.90
Little P.T.	Little	4.16	0.00	-0.02	-0.01	-0.04	-0.01	-0.04
Calectric	Littlemountain	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Lafayette	Littler	12.0	0.06	0.09	0.07	0.28	0.12	0.40
Little Tujunga P.T.	Littletujunga	2.4	0.01	0.01	0.01	0.07	0.01	0.10
Valley	Livermore	12.0	0.22	0.45	0.29	2.86	0.49	4.08
Lizard P.T.	Lizard	4.8	0.01	0.01	0.02	0.06	0.03	0.09
Madrid	Llewellyn	4.16	0.01	0.01	-0.04	0.71	-0.03	0.90
Del Sur	Lloyd	12.0	0.25	0.53	0.37	2.61	0.42	3.57
Cornuta	Lobby	12.0	0.66	0.89	0.99	5.21	1.38	5.90
Chino	Lobet	12.0	0.76	0.95	1.14	5.80	1.74	7.14
Pechanga	Lobo	12.0	0.31	0.64	0.36	3.95	0.70	5.75
Beverly	Local	16.0	0.20	0.42	0.32	2.38	0.37	2.57
Lennox	Lock	4.16	0.14	0.19	0.21	1.41	0.23	1.47
Kramer	Lockhart	33.0	0.08	0.13	0.14	1.04	0.14	1.05

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Nelson	Lockner	12.0	0.25	0.72	0.36	3.40	0.45	4.79
Ravendale	Locksley	16.0	0.45	1.10	0.63	6.46	0.74	8.00
Railroad	Locomotive	12.0	0.53	0.68	0.75	4.80	1.05	7.03
Rush	Lodestar	16.0	0.01	0.01	0.01	0.07	0.02	0.09
Carmenita	Loftus	12.0	1.02	1.44	1.59	9.52	1.89	11.21
Earlimart	Logan	12.0	0.53	0.83	0.78	5.08	0.97	6.00
White Mt.	Logcabin	12.0	0.00	0.00	0.00	0.00	0.01	0.01
La Veta	Lola	12.0	0.81	1.00	1.25	5.14	1.62	5.58
Moraga	Lolita	12.0	0.27	0.48	0.37	2.54	0.61	3.33
Mesa	Lomas	16.0	0.26	0.47	0.32	3.52	0.40	4.32
Loma Vista P.T.	Lomavista	2.4	0.00	0.01	0.01	0.09	0.02	0.13
Movie	Lombard	16.0	0.38	0.65	0.55	4.26	0.74	4.85
San Marino	Lombardy	4.16	0.07	0.18	0.10	0.76	0.18	1.23
Rolling Hills	Lomita	16.0	0.92	1.20	1.48	8.04	1.59	8.17
Las Lomas	London	12.0	0.25	0.39	0.27	3.17	0.49	4.15
Long P.T.	Long	4.16	0.03	0.02	0.03	0.35	0.03	0.36
Bovine	Longhorn	12.0	0.74	0.67	1.01	5.21	1.64	6.69
Look Out P.T.	Lookoutp.T.	2.4	0.00	0.00	0.00	0.00	0.00	0.00
State Street	Loop	12.0	0.08	0.21	0.12	1.20	0.13	1.23
Rialto	Loper	4.16	0.09	0.20	0.13	1.12	0.15	1.37
San Fernando	Lopez	16.0	0.94	1.15	1.38	5.86	1.96	6.73
Torrance	Loquat	16.0	1.02	1.02	1.50	6.79	2.11	7.97
Savage	Lorene	12.0	0.57	0.67	0.84	3.90	1.46	5.02
Naples	Loreta	4.16	0.02	0.07	0.02	0.50	0.04	0.62
Jefferson	Lorna	12.0	0.58	0.93	0.84	5.15	1.29	6.44
Isla Vista	Loscarneros	16.0	0.01	0.02	0.02	0.09	0.02	0.11
Phelan	Lotto	12.0	0.42	0.84	0.64	4.34	0.71	6.06
Barre	Lotus	12.0	0.31	0.56	0.47	3.31	0.60	3.72
Rialto	Love	4.16	0.10	0.15	0.15	1.09	0.17	1.15
Sierra Madre	Lowell	4.16	0.12	0.10	0.14	0.69	0.37	1.04
Oak Grove	Lowry	12.0	0.78	1.31	1.14	7.59	1.89	8.63
Piute	Lucerne	12.0	0.11	0.16	0.17	1.19	0.19	1.49
Broadway	Lucia	12.0	0.45	0.90	0.67	5.31	0.81	6.02
Beverly	Luckman	16.0	0.79	1.55	1.19	8.15	1.47	8.68
Redlands	Lugonia	12.0	0.32	0.61	0.48	3.38	0.66	3.97
Pechanga	Luiseno	33.0	0.19	0.25	0.30	1.96	0.32	2.02
Potrero	Luna	16.0	0.68	0.76	0.97	3.92	1.68	5.01
Oasis	Lupine	12.0	0.52	0.72	0.82	4.34	1.00	4.79
Oldfield	Luray	4.16	0.08	0.12	0.11	0.76	0.15	0.87
Luring P.T.	Luring	2.4	0.02	0.05	0.03	0.24	0.03	0.29
Newcomb	Lusk	12.0	0.67	1.21	0.95	6.04	1.48	7.42
Bixby	Luther	4.16	0.11	0.17	0.15	0.99	0.18	1.13
Imperial	Luxor	12.0	0.79	1.02	1.20	6.63	1.63	7.72
Gale	Luz	33.0	0.00	0.00	0.00	0.01	0.00	0.01
Ellis	Lyell	12.0	0.37	0.27	0.45	2.51	1.08	3.54
Lynwood	Lyndora	4.16	0.12	0.17	0.17	1.07	0.20	1.23
Lark Ellen	Lynne	12.0	0.84	1.09	1.24	5.30	1.88	6.45
Lampson	Lynx	12.0	0.23	0.45	0.36	2.61	0.39	2.73
Newhall	Lyons	16.0	0.53	1.02	0.78	5.39	1.05	6.33
Alder	Lytle	12.0	0.62	1.13	0.91	7.20	1.36	9.34
Sunny Dunes	Lytton	4.16	0.14	0.17	0.20	0.76	0.39	0.98
Culver	M.G.M.	16.0	0.53	1.08	0.83	6.04	0.93	6.27
Cudahy	Maas	4.16	0.14	0.23	0.21	1.43	0.25	1.64
La Veta	Mable	12.0	0.88	1.63	1.39	9.67	1.47	9.97
Chestnut	Macadamia	12.0	0.45	0.89	0.69	5.24	0.81	5.86
Industry	Machine	12.0	0.84	1.06	1.29	6.57	1.74	7.44
Borrego	Macho	12.0	0.19	0.50	0.21	3.63	0.27	4.85
Soquel	Maciel	12.0	0.39	0.51	0.43	2.47	1.42	4.93
Roadway	Mack	12.0	0.30	0.40	0.38	1.81	0.80	2.89
Tipton	Macomber	12.0	0.65	1.01	1.01	9.45	1.11	12.75
Muscoy	Macy	4.16	0.10	0.18	0.14	1.11	0.18	1.30
Walteria	Madera	4.16	0.05	0.03	0.04	0.70	0.05	0.89
Colorado	Madison	16.0	1.06	1.89	1.53	9.20	2.18	10.42
Madrone P.T.	Madrone	4.16	0.07	0.14	0.09	0.98	0.11	1.17
Irvine	Magazine	12.0	0.12	0.21	0.16	1.76	0.19	2.03
Orange	Magenta	12.0	0.72	1.14	1.09	7.34	1.37	8.21
Saugus	Magic	16.0	0.69	0.80	1.08	6.59	1.27	7.85
Bedford	Magnetic	4.16	0.09	0.24	0.12	1.14	0.16	1.51
Chase	Magnolia	12.0	0.47	0.77	0.65	3.95	1.29	5.65

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Etiwanda	Magoo	12.0	0.38	0.82	0.49	4.06	0.94	6.28
Victor	Magua	12.0	0.54	0.63	0.81	3.91	1.17	4.82
Latigo	Maguire	16.0	0.27	0.55	0.35	2.93	0.48	4.09
Maiden P.T.	Maiden	4.16	0.00	0.06	-0.01	0.33	-0.01	0.58
Edinger	Mainst.	4.16	0.11	0.16	0.18	1.21	0.19	1.34
Ontario	Maitland	4.16	0.10	0.15	0.15	0.75	0.25	0.91
Soquel	Maize	12.0	0.35	0.54	0.47	2.99	1.00	4.45
Palos Verdes	Major	4.16	-0.01	0.05	-0.08	0.73	-0.08	1.25
Palos Verdes	Malagacove	4.16	0.04	0.11	0.06	0.93	0.07	1.40
Vail	Malden	16.0	2.14	2.69	3.19	14.63	4.78	18.26
Railroad	Mallet	12.0	0.26	0.40	0.27	3.37	0.51	5.28
Saticoy	Maloy	16.0	0.09	0.12	0.09	1.37	0.11	1.74
Laguna Bell	Malt	16.0	0.09	0.17	0.14	0.95	0.16	0.97
North Oaks	Mamba	16.0	0.72	1.35	1.02	7.17	1.40	8.24
Minaret	Mamie	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Morningside	Manchester	4.16	0.08	0.16	0.12	0.86	0.14	1.03
Citrus	Mandarin	12.0	0.75	0.82	1.05	4.30	2.12	5.84
Limestone	Manganese	12.0	0.62	1.07	0.91	6.19	1.29	7.25
Flanco	Mango	4.16	0.08	0.17	0.12	0.92	0.15	1.13
Lafayette	Mangrum	12.0	0.65	0.85	1.02	5.01	1.28	5.40
Hathaway	Manila	4.16	0.08	0.23	0.09	1.11	0.11	1.71
Indian Wells	Manitou	12.0	0.72	1.13	1.03	4.69	1.93	6.95
Declez	Manning	12.0	0.90	1.06	1.26	4.52	2.45	6.41
Anita	Manor	4.16	0.05	0.15	0.06	0.95	0.08	1.40
Colton	Mansa	12.0	0.05	0.15	0.06	0.18	0.22	0.67
Randall	Manteca	12.0	0.42	0.62	0.54	3.32	1.26	5.17
Haveda	Manuel	4.16	0.00	-0.02	-0.07	0.84	-0.06	1.04
Cameron	Manville	12.0	0.02	0.04	0.03	0.19	0.03	0.22
Goshen	Manzanillo	12.0	0.43	0.67	0.63	4.61	0.80	6.02
Victor	Manzer	12.0	0.51	0.91	0.79	5.32	0.83	6.62
Eric	Mapes	12.0	1.11	1.46	1.64	8.53	2.38	10.04
Beverly	Maple	4.16	0.16	0.24	0.22	1.06	0.48	1.61
Somerset	Maplewood	12.0	0.71	0.91	1.07	4.92	1.57	5.70
Borrego	Maraca	12.0	0.30	0.53	0.42	3.38	0.55	3.92
Mascot	Marauder	12.0	0.59	0.91	0.89	6.08	1.38	7.21
Declez	Marble	12.0	0.54	0.69	0.84	4.20	1.13	5.04
Francis	Marbuck	12.0	1.05	1.27	1.57	6.89	2.26	8.00
Madrid	Marcellina	4.16	0.03	0.04	0.04	0.28	0.05	0.36
Padua	Marconi	12.0	0.60	0.89	0.89	5.59	1.39	6.84
Haskell	Marcus	16.0	0.49	0.95	0.64	4.67	1.11	6.62
Atwood	Marda	12.0	0.16	0.49	0.20	2.37	0.24	3.62
Arcadia	Marendale	16.0	1.41	1.84	2.25	10.37	2.51	10.94
Alhambra	Marengo	4.16	0.07	0.13	0.07	0.74	0.13	1.05
Felton	Margaret	16.0	1.31	1.51	2.00	8.33	2.68	9.36
Alhambra	Marguerita	16.0	0.52	0.82	0.75	4.80	1.09	5.90
Rancho	Marianna	12.0	0.59	0.75	0.83	3.31	1.68	5.02
Barre	Marigold	12.0	0.54	0.86	0.79	5.22	1.08	6.02
Marina P.T.	Marina	4.16	0.04	0.08	0.05	0.45	0.06	0.48
Palmdale	Mark	12.0	0.36	0.44	0.56	3.50	0.62	3.83
Oldfield	Market	4.16	0.12	0.21	0.18	1.41	0.19	1.67
Cima	Marl	16.0	0.03	0.07	0.05	0.38	0.06	0.39
Hathaway	Marland	12.0	0.29	0.60	0.43	3.34	0.55	3.89
Culver	Marlene	16.0	0.31	0.48	0.44	4.04	0.51	4.31
Thornhill	Marquis	12.0	0.23	0.31	0.35	1.85	0.45	2.14
Cabrillo	Marriott	12.0	0.53	1.25	0.86	7.43	0.87	7.66
Bowl	Mars	12.0	0.29	0.55	0.41	2.84	0.53	3.24
Earlimart	Marsh	12.0	0.63	0.89	0.93	5.52	1.19	6.53
Marine	Marshall	16.0	1.70	1.91	2.63	10.50	3.21	11.30
Artesia	Martha	4.16	0.14	0.18	0.20	1.02	0.35	1.22
Davidson City	Martin	4.16	0.15	0.20	0.21	1.46	0.24	1.69
Chiquita	Martini	12.0	0.18	0.57	0.17	3.54	0.28	5.37
Somerset	Marty	12.0	0.55	0.67	0.80	3.56	1.36	4.30
Nelson	Marvin	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Culver	Marvista	16.0	0.63	1.18	0.99	6.70	1.24	7.20
Etiwanda	Marx	12.0	0.47	0.66	0.59	3.52	1.41	5.56
La Veta	Mary	12.0	0.44	0.82	0.64	4.45	0.85	5.05
Carolina	Maryland	12.0	0.23	0.51	0.30	3.13	0.38	3.86
Gilbert	Mashie	12.0	0.28	0.54	0.41	3.27	0.56	3.83
Covina	Masonic	4.16	0.03	0.09	0.03	0.40	0.06	0.67

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Carolina	Massachusetts	12.0	0.58	0.87	0.79	4.61	1.46	6.23
Nelson	Massacre	12.0	0.45	0.81	0.63	4.17	0.96	5.34
Harding	Masser	4.16	0.56	0.62	0.75	1.88	1.62	2.89
Pico	Mast	12.0	0.12	0.63	0.19	4.12	0.20	4.82
Concho	Matador	12.0	0.58	0.89	0.82	3.83	1.50	5.59
Pechanga	Matera	12.0	0.62	1.18	0.86	5.77	1.26	7.02
Pepper	Mateus	12.0	0.28	0.54	0.42	2.91	0.56	3.42
Tulare	Mathias	12.0	0.74	0.99	1.28	5.30	2.00	6.42
Ojai	Matilija	16.0	0.80	1.00	1.05	5.05	1.68	6.60
Fullerton	Matlock	12.0	0.07	0.40	0.05	1.84	0.07	3.14
Oldfield	Matney	4.16	0.07	0.14	0.08	0.86	0.12	1.06
Barstow	Mauel	12.0	0.31	0.62	0.42	2.79	0.60	3.82
Gonzales	Maulhardt	16.0	1.04	1.23	1.65	7.22	1.88	7.94
Savage	Maunaloa	12.0	0.53	0.63	0.89	3.69	1.11	4.19
Wilsona	Maverick	12.0	0.08	0.16	0.09	0.82	0.18	1.27
Coffee	Maxim	12.0	0.76	1.34	1.14	6.86	1.53	9.18
Haskell	Maximus	16.0	0.12	0.39	-0.01	2.81	0.10	4.74
Rivera	Maxine	4.16	0.13	0.16	0.17	1.22	0.29	1.52
Saticoy	Maxson	16.0	0.81	0.85	1.17	5.84	1.90	6.72
Indian Wells	Mayan	12.0	0.70	0.83	1.00	3.87	2.03	5.23
Cortez	Maybell	12.0	0.88	1.20	1.23	5.53	2.35	7.98
Elsinore	Mayer	33.0	0.00	0.00	0.00	0.01	0.00	0.01
Ramona	Mayfair	4.16	0.09	0.04	0.11	0.75	0.23	0.98
Sharon	Mayfield	4.16	0.05	0.08	0.05	0.60	0.11	0.93
Bullis	Mayo	16.0	0.62	0.86	0.98	5.08	1.11	5.63
Lancaster	Mays	12.0	0.42	0.57	0.63	2.73	0.95	3.17
Brea	Mazatlan	12.0	0.22	0.37	0.29	1.96	0.61	3.09
El Sobrante	Mcallister	12.0	0.38	0.51	1.14	4.45	2.73	6.85
Newhall	Mcbean	16.0	0.81	1.49	1.10	7.87	1.71	10.10
Belding	Mccallum	4.16	0.21	0.30	0.28	1.00	0.70	1.74
Beverly	Mccarty	16.0	0.41	0.89	0.66	5.11	0.69	5.23
Amargo	Mccaslin	4.16	0.01	0.02	0.02	0.13	0.03	0.15
Mc Clary P.T.	Mcclary	4.16	0.04	0.04	0.07	0.28	0.13	0.37
McClenny P.T.	Mcclenny	2.4	0.00	0.01	0.01	0.03	0.01	0.04
Jersey	Mccloud	16.0	0.61	0.93	0.96	5.87	1.11	6.53
Browning	Mcclure	12.0	0.24	0.33	0.34	1.88	0.46	2.23
Cabrillo	Mccormick	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Blythe City	Mccoy	33.0	0.01	0.01	0.01	0.05	0.01	0.06
Lennox	Mcdonnell	16.0	0.86	1.07	1.31	5.74	1.76	6.32
Wimbledon	Mcenroe	12.0	1.31	1.79	2.12	11.96	2.23	13.40
Marine	Mcewan	16.0	0.06	0.06	0.05	0.65	0.08	0.81
Browning	Mcfarland	12.0	0.38	0.58	0.57	3.76	0.69	4.40
Sherwin	Mcgee	12.0	0.06	0.20	0.08	1.01	0.10	1.29
Brookhurst	Mckeever	12.0	0.85	0.98	1.26	6.30	1.70	7.25
Mckevett P.T.	Mckevett	4.16	0.06	0.06	0.07	0.27	0.13	0.36
Fremont	Mckinley	4.16	0.10	0.15	0.14	1.13	0.15	1.27
Newcomb	Mclaughlin	12.0	0.28	0.96	0.38	4.99	0.40	7.18
Thornhill	Mcmanus	12.0	0.76	1.19	1.11	5.54	1.92	7.71
Lucas	Mcnab	4.16	0.13	0.12	0.16	0.85	0.37	1.20
Cardiff	Meadowbrook	12.0	0.45	0.78	0.69	4.64	0.86	5.10
Wrightwood	Meadowlark	12.0	0.04	0.09	0.05	0.44	0.08	0.51
Upland	Meagan	12.0	0.54	1.01	0.80	5.96	1.05	7.00
Beverly	Meander	16.0	0.53	1.17	0.73	5.96	1.15	7.96
Cucamonga	Mears	12.0	0.48	0.99	0.75	6.31	0.85	7.42
Villa Park	Meats	12.0	0.54	1.00	0.70	4.88	1.21	6.71
Trophy	Medal	12.0	0.59	0.85	0.76	4.90	1.66	7.35
Lancaster	Medallion	12.0	0.37	0.52	0.52	2.56	0.81	3.34
Terrace	Medford	4.16	0.09	0.17	0.13	1.07	0.16	1.20
Colorado	Medical	4.16	0.10	0.21	0.13	1.23	0.17	1.48
Bixby	Medio	4.16	0.08	0.12	0.12	0.76	0.14	0.87
Bicknell	Mednick	4.16	0.04	0.06	0.05	0.38	0.07	0.41
San Bernardino	Medusa	12.0	0.60	1.73	0.95	10.23	1.01	10.38
O'neill	Melinda	12.0	0.15	0.70	0.10	3.76	0.17	5.92
La Veta	Melissa	12.0	0.38	0.68	0.55	3.68	0.79	4.35
Hi Desert	Melody	25.0	0.15	0.42	0.23	2.05	0.26	2.70
Blythe City	Melon	12.0	0.74	0.99	1.07	4.17	1.96	5.61
Hemet	Melvere	12.0	0.62	1.15	0.87	5.29	1.33	6.20
La Habra	Memory	12.0	0.45	0.97	0.62	3.53	1.30	5.50
Tennessee	Memphis	12.0	0.46	1.05	0.56	5.03	1.16	8.10

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Newcomb	Menifee	12.0	0.44	1.02	0.62	4.89	1.01	6.95
Yukon	Menlo	4.16	0.13	0.20	0.19	1.13	0.24	1.31
Newhall	Mentry	16.0	0.40	0.86	0.48	3.73	1.00	5.98
Telegraph	Mercado	12.0	0.51	1.23	0.74	7.02	0.85	8.61
Inglewood	Mercantile	4.16	0.08	0.13	0.09	0.45	0.16	0.63
Vera	Mercedes	12.0	0.97	1.09	1.41	6.38	2.28	7.88
Newmark	Mercer	16.0	0.77	1.38	1.11	7.77	1.48	8.88
Calectric	Meredith	33.0	0.51	1.21	0.82	8.44	0.83	10.36
Anita	Meridian	16.0	1.37	2.24	3.59	13.66	8.02	21.84
Latigo	Merlin	16.0	0.18	0.57	0.22	2.69	0.31	4.06
Pauba	Merlot	12.0	0.15	0.48	0.15	3.00	0.22	4.59
Flanco	Merril	4.16	0.10	0.17	0.16	0.98	0.23	1.16
Poplar	Merrit	12.0	0.53	0.66	0.80	4.71	1.01	5.72
Venida	Merryman	12.0	0.24	0.49	0.29	1.85	0.52	2.61
Amador	Mervin	4.16	0.16	0.26	0.23	1.48	0.27	1.78
Yucaipa	Mesagrande	12.0	0.18	0.28	0.40	2.28	0.74	3.19
Milliken	Mescal	12.0	1.00	1.23	1.52	6.16	2.07	7.15
Culver	Mesmer	4.16	0.03	0.02	-0.02	0.66	0.01	0.89
Hesperia	Mesquite	12.0	0.71	1.16	1.02	6.29	1.44	8.57
Gisler	Meteor	12.0	0.90	1.19	1.43	7.30	1.64	7.91
Upland	Metro	12.0	0.73	1.19	1.08	7.68	1.51	9.71
Cummings	Mettler	12.0	0.45	0.72	0.58	4.69	0.87	6.34
Clark	Metz	4.16	0.04	0.06	0.02	0.91	0.02	1.24
Ely	Mexico	12.0	0.45	0.49	0.60	3.94	1.16	5.23
Sullivan	Miami	4.16	0.12	0.16	0.18	1.22	0.19	1.37
Crest	Mica	16.0	0.33	0.34	0.40	1.59	1.22	2.90
Corona	Michael	12.0	1.09	1.50	1.70	9.16	2.08	11.12
Cortez	Michelle	12.0	0.48	0.55	0.68	2.65	1.30	3.53
Signal Hill	Michigan	4.16	0.03	0.07	0.00	0.77	0.01	1.03
Line Creek	Micro	4.16	0.01	0.02	0.02	0.12	0.03	0.13
Lafayette	Middlecoff	12.0	0.32	0.73	0.45	3.59	0.53	4.66
Saticoy	Middleroad	16.0	0.92	1.11	1.63	6.68	2.72	8.01
Quinn	Midge	12.0	0.50	0.72	0.77	5.79	0.88	6.92
Milliken	Midori	12.0	0.52	0.66	0.82	4.24	0.93	4.59
Liberty	Midvalle	12.0	0.45	0.74	0.87	5.40	1.69	7.63
Cedarwood	Midway	4.16	0.05	0.10	0.08	0.53	0.12	0.71
Ramona	Midwick	4.16	0.09	0.10	0.12	0.75	0.19	0.92
Alon	Miguel	12.0	0.17	0.22	0.26	1.66	0.30	2.23
Marion	Mildred	12.0	0.34	0.83	0.43	5.05	0.54	6.45
Trophy	Miler	12.0	0.52	0.68	0.82	4.94	0.98	5.65
Huntington Park	Miles	4.16	0.13	0.20	0.20	1.17	0.23	1.32
Tulare	Milk	12.0	0.70	1.38	1.03	7.89	1.61	9.27
Santa Fe Springs	Mill	12.0	0.58	0.78	0.92	4.81	1.06	4.97
Nogales	Millennium	12.0	0.74	0.75	0.93	4.52	2.23	6.83
Walteria	Miller	4.16	0.09	0.17	0.13	1.14	0.15	1.35
Passons	Millergrove	12.0	0.98	1.15	1.41	6.31	2.44	8.24
Alon	Millpoint	12.0	0.41	0.56	0.63	3.84	0.82	4.74
Valdez	Milo	16.0	0.56	1.09	0.82	6.01	1.19	7.15
Santa Barbara	Milpas	16.0	0.94	1.51	1.32	8.80	1.90	9.98
Tamarisk	Mimosa	12.0	0.58	0.89	0.83	3.83	1.51	5.63
Visalia	Mineral	12.0	0.65	0.87	1.01	3.87	1.68	5.02
Savage	Mingo	12.0	0.52	0.63	0.77	3.64	1.17	4.56
Carolina	Minnesota	12.0	0.77	1.47	1.14	7.54	1.51	8.43
El Nido	Minnow	16.0	0.81	1.14	1.30	6.85	1.43	7.02
Nelson	Minor	12.0	0.72	0.85	1.05	4.54	1.89	5.58
Crown	Minosa	12.0	0.64	1.34	0.96	6.56	1.35	7.81
San Bernardino	Minotaur	12.0	0.41	0.76	0.60	3.68	0.83	4.04
Saugus	Mintcanyon	16.0	0.82	1.42	1.24	8.81	1.43	10.47
Liberty	Minuteman	12.0	0.63	1.51	0.92	7.69	1.40	9.13
Carmenita	Mira	12.0	0.55	0.81	0.88	5.80	0.97	6.55
Ridgecrest	Miraclecity	4.8	0.02	0.05	0.04	0.32	0.06	0.37
Rolling Hills	Miralesta	16.0	0.59	0.70	0.95	5.27	1.01	5.35
Montecito	Miramar	4.16	0.04	0.13	0.05	0.46	0.07	0.80
Huntington Park	Miramonte	4.16	0.10	0.14	0.15	0.92	0.17	0.99
Savage	Mirror	12.0	0.61	0.71	0.89	3.45	1.57	4.63
San Fernando	Mission	16.0	1.45	1.77	2.26	11.30	2.80	11.95
Riverway	Mississippi	12.0	0.53	1.04	0.77	4.93	1.00	6.55
South Gate	Missouri	4.16	0.11	0.17	0.17	1.09	0.19	1.23
Capitan	Mist	16.0	0.32	0.36	0.45	1.64	0.79	2.04

Substation	Distribution Circuit	Voltage (kV)	Scenario 1 Coincident Capacity (MW)	Scenario 1 Total Capacity (MW)	Scenario 2 Coincident Capacity (MW)	Scenario 2 Total Capacity (MW)	Scenario 3 Coincident Capacity (MW)	Scenario 3 Total Capacity (MW)
Tamarisk	Mistletoe	12.0	0.85	1.34	1.23	5.72	2.22	8.43
Seabright	Mitchell	12.0	0.06	0.13	0.10	0.77	0.11	0.81
Moab P.T.	Moab	4.16	0.02	0.02	0.02	0.12	0.06	0.22
North Oaks	Moccasin	16.0	0.99	1.53	1.37	7.28	2.21	8.89
Mockingbird P.T.	Mockingbird	12.0	0.07	0.10	0.10	0.48	0.16	0.60
Jefferson	Modelo	12.0	0.39	0.79	0.54	4.13	0.85	5.61
O'neill	Modjeska	12.0	0.16	0.53	0.14	3.36	0.17	5.16
Lemon Cove	Moffitt	12.0	0.10	0.15	0.13	0.61	0.21	0.81
Sierra Madre	Mohawk	4.16	0.15	0.22	0.20	0.89	0.44	1.37
Indian Wells	Mohican	12.0	0.98	1.63	1.38	6.01	2.80	9.53
Pico	Mole	12.0	0.00	0.00	0.01	0.03	0.01	0.03
Hathaway	Molino	12.0	0.34	0.66	0.47	3.63	0.61	4.12
Athens	Mona	4.16	0.14	0.17	0.22	1.24	0.24	1.29
Porterville	Monache	12.0	0.73	1.01	1.13	7.96	1.38	9.85
Royal	Monarch	16.0	0.48	0.72	0.67	4.66	0.99	5.78
Santiago	Money	12.0	0.27	0.58	0.42	3.46	0.46	3.71
Johanna	Monopoly	12.0	0.47	0.84	0.75	5.93	0.81	6.57
Woodville	Monroe	12.0	0.25	0.43	0.36	2.85	0.44	3.42
Oak Grove	Monson	12.0	1.03	1.24	1.62	8.51	1.92	8.86
Yorba Linda	Monsoon	12.0	0.77	1.03	1.16	5.43	1.58	6.19
Signal Hill	Montana	12.0	0.37	0.45	0.55	2.08	0.82	2.38
Barstow	Montara	33.0	0.11	0.28	0.17	1.64	0.17	1.68
San Antonio	Montclair	12.0	0.54	0.66	0.80	2.77	1.25	3.28
Royal	Montgomery	16.0	0.56	0.61	0.68	4.73	1.45	6.74
Canadian P.T.	Montreal	12.0	0.17	0.39	0.23	1.73	0.32	2.27
La Canada	Montrose	4.16	0.16	0.22	0.22	0.99	0.49	1.41
Cardiff	Monty	12.0	0.28	0.36	0.44	2.08	0.50	2.23
Joshua Tree	Monument	12.0	0.46	0.55	0.68	2.66	1.05	3.07
Carmenita	Moody	12.0	0.49	0.70	0.77	5.22	0.95	6.02
Walteria	Moon	4.16	0.09	0.06	0.10	1.15	0.12	1.21
Repetto	Moonbeam	4.16	0.04	0.03	0.03	0.56	0.07	0.74
Quartz Hill	Moonglow	12.0	0.35	0.58	0.49	2.91	0.89	4.13
Gisler	Moonwalk	12.0	1.12	1.30	1.67	7.13	2.47	8.36
Fruitland	Moore	4.16	0.15	0.21	0.20	1.21	0.27	1.39
Randall	Mora	12.0	0.73	1.19	1.10	7.07	1.52	8.38
Layfair	Moran	12.0	0.94	1.17	1.43	6.74	2.02	7.90
Santa Susana	Moreland	16.0	0.91	1.06	1.30	6.76	2.11	8.43
Maraschino	Morello	12.0	0.14	0.19	0.23	1.19	0.27	1.34
Ditmar	Morgan	4.16	0.03	-0.01	0.01	0.43	0.03	0.47
Moorpark	Morganstein	16.0	0.73	1.55	0.89	7.56	1.79	11.72
Huston	Moritz	12.0	0.29	0.66	0.43	3.64	0.50	4.21
Morongo P.T.	Morongo	12.0	0.14	0.23	0.18	1.03	0.29	1.47
Saugus	Morrie	16.0	1.03	1.33	1.63	8.63	1.87	9.45
Auld	Morris	12.0	0.12	0.52	0.04	2.52	0.20	4.66
Ellis	Morrison	12.0	0.42	0.57	0.45	4.97	0.85	6.71
Cabrillo	Morse	12.0	0.21	0.67	0.19	4.59	0.25	6.17
Porterville	Morton	4.16	0.21	0.31	0.31	1.08	0.55	1.57
Narod	Mosebrook	12.0	0.57	0.99	0.88	5.56	1.11	6.28
Kimball	Mosquito	12.0	0.69	1.05	1.05	7.11	1.36	7.92
Dalton	Mossberg	12.0	0.12	0.16	0.18	1.13	0.22	1.42
Los Cerritos	Mossman	12.0	0.12	0.24	0.16	1.38	0.21	1.68
Lighthipe	Motz	12.0	0.61	0.73	0.94	4.52	1.20	4.91
Arro	Mountain	4.16	0.09	0.11	0.13	0.99	0.15	1.05
Windsor Hills	Mowder	4.16	0.06	0.15	0.09	0.88	0.09	1.18
Moynier P.T.	Moynier	4.16	0.01	0.01	0.00	0.23	0.00	0.30
Mt. Givens P.T.	Mt.Givens	2.4	0.00	0.00	0.00	0.01	0.00	0.01
Elsinore	Muddy	12.0	0.50	0.92	0.73	4.90	1.02	5.87
Sixteenth Street	Muffin	12.0	0.41	0.68	0.63	4.12	0.79	4.44
Colonia	Mugu	16.0	1.03	1.23	1.54	6.15	2.19	7.57
Irvine	Muirlands	12.0	0.23	0.64	0.21	4.77	0.29	6.33
Friendly Hills	Mulberry	4.16	0.06	0.10	0.08	0.66	0.12	0.85
Yermo	Mulecanyon	12.0	0.29	0.41	0.40	2.13	0.57	2.77
Fernwood	Mulford	16.0	0.00	0.00	0.00	0.00	0.00	0.00
Crater	Mulholland	16.0	0.13	0.44	0.15	1.87	0.24	3.02
Del Rosa	Mulkey	12.0	0.70	1.17	0.98	5.64	1.50	6.62
Murphy	Mulligan	12.0	0.12	0.13	0.18	0.88	0.25	1.00
Universal	Mummy	12.0	0.01	0.01	0.01	0.08	0.01	0.08
Longdon	Muriel	4.16	0.17	0.19	0.25	1.13	0.42	1.34
Redman	Muroc	12.0	0.01	0.04	0.01	0.13	0.02	0.24

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Palm Canyon	Murray	12.0	0.30	0.64	0.44	2.65	0.68	4.05
Ivar	Muscatel	4.16	0.09	0.12	0.12	0.85	0.19	1.02
Timoteo	Muse	12.0	0.69	1.16	0.91	5.17	1.68	7.27
Piute	Museum	12.0	0.11	0.14	0.17	1.14	0.20	1.40
Pioneer	Musket	12.0	1.24	1.56	1.85	8.30	2.77	9.83
Hanford	Mussel	12.0	0.72	0.94	1.02	4.18	1.76	5.51
Isabella	Mustang	12.0	0.30	0.45	0.45	2.39	0.66	2.95
Redlands	Mutual	12.0	0.32	0.72	0.43	3.76	0.72	5.35
Ravendale	Myda	4.16	0.03	0.08	0.02	0.63	0.02	0.98
Irvine	Myford	12.0	0.22	0.39	0.21	2.73	0.34	3.84
Monrovia	Myrtle	4.16	0.11	0.12	0.12	0.76	0.32	1.23
Santa Fe Springs	Mystic	12.0	0.83	1.08	1.27	6.16	1.72	6.68
Graham	Nadeau	4.16	0.09	0.13	0.13	0.81	0.15	0.90
Temple	Nadine	4.16	0.07	0.08	0.10	0.71	0.18	0.95
Doheny	Nadir	4.16	0.07	0.20	0.10	0.82	0.20	1.35
Alessandro	Nance	12.0	0.29	0.57	0.42	2.98	0.64	3.99
Stirrup	Nancy	4.16	0.10	0.16	0.11	0.82	0.26	1.39
Valley	Napa	12.0	0.30	0.48	0.46	3.60	0.52	3.95
Maraschino	Napoleon	12.0	0.38	0.88	0.56	5.02	0.66	6.30
Walteria	Narbonne	4.16	0.06	0.06	0.04	0.95	0.07	1.23
Daisy	Nardo	4.16	0.01	0.02	0.02	0.09	0.03	0.12
Shuttle	Nasa	12.0	0.78	1.10	1.11	5.13	1.72	6.77
Downey	Nash	4.16	0.10	0.18	0.11	1.08	0.22	1.59
Tennessee	Nashville	12.0	0.34	0.66	0.42	3.60	0.75	5.03
Bedford	Nason	4.16	0.08	0.17	0.12	0.77	0.20	0.98
Victor	Nassau	12.0	0.47	0.55	0.65	2.89	1.33	4.33
Wimbledon	Nastase	12.0	0.41	0.63	0.65	4.03	0.73	4.57
La Veta	Natalie	12.0	0.45	0.92	0.70	5.17	0.82	5.42
Cudahy	National	4.16	0.10	0.14	0.16	1.00	0.18	1.04
Valley	Nations	12.0	0.30	0.70	0.43	3.26	0.72	4.85
Levy	Naumann	16.0	0.49	0.73	0.66	4.42	0.90	6.23
Mentone	Navel	12.0	0.24	0.76	0.33	3.40	0.44	5.09
Hanford	Navigator	12.0	0.72	1.26	1.07	6.53	1.42	8.52
Marine	Navy	16.0	1.08	1.35	1.69	7.65	1.89	8.26
Rubidoux	Naylor	12.0	0.36	0.60	0.51	2.86	0.82	3.61
Newcomb	Neapolitan	12.0	0.40	1.14	0.50	4.09	1.20	7.70
Newhall	Neargate	16.0	0.65	1.36	0.84	6.52	1.51	9.44
Daggett	Nebo	12.0	0.00	0.00	0.00	0.00	0.00	0.00
South Gate	Nebraska	4.16	0.07	0.11	0.11	0.86	0.11	0.96
Friendly Hills	Nedra	4.16	0.08	0.10	0.10	0.58	0.23	0.88
Aqueduct	Needle	12.0	0.54	0.76	0.79	4.18	1.28	5.67
Somerset	Negel	4.16	0.17	0.24	0.25	1.60	0.31	1.83
Live Oak	Neibel	12.0	0.57	0.46	0.73	2.52	1.78	3.83
Blythe City	Neighbors	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Santa Fe Springs	Nelles	12.0	1.32	1.69	2.11	10.44	2.38	10.76
Victoria	Nelson	16.0	0.61	1.02	0.87	6.31	1.05	6.81
Layfair	Nemaha	4.16	0.05	0.10	0.06	0.61	0.13	0.94
Marine	Neon	16.0	0.95	1.01	1.47	5.96	1.77	6.40
Modena	Nepal	12.0	0.28	0.65	0.32	3.09	0.76	5.31
Haskell	Nero	16.0	-0.10	-0.27	-0.28	-0.04	-0.24	0.10
Del Amo	Nestle	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Fremont	Nestor	4.16	0.14	0.23	0.21	1.60	0.22	1.82
Sepulveda	Nevada	4.16	0.05	0.18	0.04	1.26	0.05	1.77
Jefferson	Newcastle	12.0	0.75	0.96	1.25	8.49	1.46	10.23
Octol	Newman	12.0	0.88	1.15	1.37	9.36	1.72	11.61
Allen	Newyork	4.16	0.07	0.11	0.19	0.98	0.41	1.53
Tapia	Nicholas	16.0	0.69	1.35	1.04	7.39	1.35	8.29
Limestone	Nickel	12.0	0.45	0.78	0.52	4.62	0.98	6.52
Rector	Nickerson	12.0	0.64	0.93	0.91	4.63	1.43	5.97
Randall	Nicklin	12.0	0.32	0.50	0.45	3.65	0.64	4.37
Highland	Nicole	12.0	0.30	0.45	0.40	2.32	0.81	3.39
Nidever P.T.	Nidever	2.4	0.01	0.05	0.01	0.25	0.01	0.40
Lockheed	Nighthawk	16.0	1.13	1.59	1.75	12.04	1.98	12.52
San Bernardino	Nike	12.0	0.36	0.81	0.57	4.51	0.63	4.65
Rio Hondo	Nile	12.0	0.38	0.52	0.51	4.08	0.59	4.80
Gisler	Nimbus	12.0	0.99	1.22	1.48	6.63	1.97	7.69
Sawtelle	Nimitz	16.0	1.78	3.10	5.69	14.98	14.08	27.53
Santa Monica	Ninthst	4.16	0.14	0.22	0.20	0.96	0.34	1.17
Mt. Pass A	Nipton	33.0	0.31	0.46	0.49	3.58	0.52	3.64

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Inglewood	Nisley	16.0	0.40	0.64	0.61	4.33	0.68	4.91
Friendly Hills	Nixon	4.16	0.14	0.17	0.19	0.93	0.43	1.24
Woodville	Noakes	12.0	0.28	0.35	0.42	2.31	0.60	2.84
Sunnyside	Noamerican	12.0	0.35	0.61	0.54	3.97	0.60	4.44
Manhattan	Nobeach	4.16	0.08	0.17	0.13	1.33	0.15	1.82
Noble P.T.	Noble	12.0	0.00	0.00	0.00	0.01	0.00	0.01
Pechanga	Noche	12.0	0.18	0.67	0.17	3.48	0.30	5.71
Ontario	Nocta	4.16	0.13	0.20	0.19	1.18	0.27	1.36
Ivar	Noel	4.16	0.12	0.09	0.15	0.78	0.35	1.10
Nogal P.T.	Nogal	4.16	0.02	0.09	0.03	0.42	0.03	0.68
Villa Park	Nohl	12.0	0.35	0.61	0.42	3.84	0.79	5.46
Colorado	Nomad	16.0	0.32	0.87	0.52	5.10	0.53	5.25
Firehouse	Nomex	12.0	0.47	0.84	0.68	4.58	0.96	5.62
Cypress	Nootka	12.0	0.08	0.15	0.05	1.60	0.07	2.28
Norco	Norconian	4.16	0.05	0.09	0.08	0.46	0.15	0.64
Skiland	Nordic	12.0	0.12	0.62	0.19	2.85	0.21	3.71
Costa Mesa	Nordina	4.16	0.11	0.30	0.11	1.42	0.16	2.25
Bowl	Norman	4.16	0.17	0.31	0.26	1.84	0.30	2.03
Howard	Normandie	4.16	0.17	0.26	0.24	1.48	0.29	1.73
Twentynine Palms	Northadobe	12.0	0.32	0.39	0.53	2.64	0.74	3.51
North Bay P.T.	Northbay	2.4	0.03	0.04	0.05	0.34	0.06	0.56
Shandin	Northpark	12.0	0.54	1.07	0.81	6.58	1.07	8.19
Windsor Hills	Northridge	4.16	0.03	0.07	0.03	0.44	0.03	0.63
Burnt Mill	Northshore	12.0	0.19	0.38	0.29	2.28	0.32	2.52
Ocean Park	Northside	4.16	0.16	0.30	0.22	1.59	0.28	1.85
Northstar P.T.	Northstar	12.0	0.07	0.10	0.10	0.47	0.17	0.64
Santa Fe Springs	Norton	12.0	0.92	1.24	2.17	7.18	4.41	10.61
Fairfax	Norwich	16.0	1.12	1.38	1.73	8.00	2.12	8.71
Highland	Norwood	12.0	0.54	0.85	0.81	5.46	1.14	6.54
Valley	Nova	12.0	0.27	0.53	0.38	3.11	0.55	4.07
Archibald	Novac	12.0	0.40	0.85	0.56	4.29	0.95	6.30
Firehouse	Nozzle	12.0	0.54	0.73	0.86	5.51	0.93	6.08
San Dimas	Nubia	12.0	0.60	0.76	0.91	4.11	1.21	4.69
Nursery P.T.	Nursery	4.16	0.05	0.09	0.07	0.36	0.18	0.62
Timoteo	Nurses	12.0	1.56	2.53	5.25	11.83	13.31	23.40
Indian Wells	Nusbaum	12.0	0.75	1.05	1.16	5.18	1.54	6.11
Tenaja	Nutmeg	12.0	0.19	0.54	0.24	2.29	0.36	3.63
Locust	Nylic	4.16	0.07	0.11	0.11	0.65	0.12	0.73
Montebello	Oak	4.16	0.12	0.16	0.18	1.06	0.21	1.12
Rosamond	Oakcreek	12.0	0.09	0.13	0.14	1.35	0.17	2.02
Newcomb	Oakdale	12.0	0.41	0.91	0.60	5.05	0.83	6.42
Yucaipa	Oakglen	12.0	0.38	0.59	0.77	4.39	1.36	5.93
Beverly	Oakhurst	4.16	0.12	0.13	0.17	0.64	0.33	0.89
Oak Knoll P.T.	Oakknoll	2.4	0.02	0.03	0.03	0.21	0.03	0.24
Octol	Oakland	12.0	0.40	0.64	0.60	4.77	0.70	5.92
Oaktree P.T.	Oaktree	2.4	0.01	0.03	0.02	0.14	0.04	0.24
Arcadia	Oakwood	4.16	0.11	0.14	0.13	0.81	0.38	1.43
Lancaster	Oban	12.0	0.64	1.03	0.93	5.38	1.25	6.76
Elizabeth Lake	Oboe	16.0	0.61	0.93	0.99	7.08	1.02	7.15
Observatory	Observatory	4.16	0.01	0.02	0.02	0.09	0.02	0.09
Limestone	Obsidian	12.0	0.32	0.64	0.46	3.87	0.64	4.81
Cherry	Ocana	12.0	0.12	0.41	0.19	2.61	0.21	2.99
La Fresa	Occidental	16.0	0.28	0.32	0.43	1.92	0.56	2.07
Seabright	Ocean	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Locust	Oceanic	4.16	0.13	0.24	0.19	1.33	0.23	1.52
Yukon	Octane	16.0	0.52	1.13	0.77	6.50	0.91	7.29
Washington	Offside	12.0	0.78	1.03	1.22	5.69	1.53	6.12
Costa Mesa	Ogle	4.16	0.08	0.16	0.09	0.99	0.12	1.35
Bowl	Ohio	4.16	0.14	0.22	0.21	1.36	0.24	1.51
Santa Fe Springs	Oil	12.0	0.49	0.82	0.73	4.89	0.91	5.17
Slater	Oilers	12.0	0.05	0.59	-0.21	4.53	-0.14	7.66
Fairview	Oilwell	12.0	0.55	1.25	0.87	7.38	0.94	7.87
Carolina	Oklahoma	12.0	0.45	0.79	0.62	4.46	1.11	6.13
Victor	Olancha	12.0	1.20	1.40	1.76	6.39	2.70	7.92
Twentynine Palms	Olddale	4.8	0.13	0.15	0.20	0.87	0.26	1.05
Telegraph	Olds	12.0	0.18	0.18	0.26	1.90	0.32	2.09
Victor	Oldtrails	33.0	0.02	0.02	0.02	0.16	0.03	0.18
Flanco	Oleander	4.16	0.09	0.13	0.12	0.73	0.20	0.92
Porterville	Olive	4.16	0.19	0.22	0.27	0.88	0.46	1.17

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Alessandro	Oliver	33.0	0.30	0.65	0.48	3.83	0.49	3.97
Rosemead	Olney	16.0	0.55	0.93	0.74	4.72	1.14	5.86
Las Lomas	Olso	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Levy	Olson	16.0	1.62	2.11	2.45	15.14	3.33	19.60
O'neill	Olympiad	12.0	0.08	0.63	0.01	2.94	0.03	5.30
Trask	Omaha	12.0	0.86	0.98	1.23	6.01	1.90	7.43
Murphy	O'Malley	12.0	0.66	0.82	1.01	4.51	1.28	5.00
Telegraph	Omega	12.0	0.60	0.69	0.78	3.76	1.89	5.66
Telegraph	Omicron	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Yucca	Onaga	12.0	1.07	1.40	1.62	7.15	2.14	8.50
Jefferson	Onbord	12.0	0.55	0.88	0.75	4.25	1.51	6.19
Blythe City	Onion	12.0	1.18	1.53	1.73	6.49	2.92	8.36
Redondo	Opal	4.16	0.02	0.04	0.01	0.53	0.02	0.66
Rush	Opportunity	16.0	0.77	1.27	1.13	8.20	1.55	9.89
Sunnyside	Ora	4.16	0.12	0.15	0.16	1.23	0.20	1.37
Venida	Orangeblossom	12.0	0.32	0.55	0.57	3.62	1.03	4.76
Gisler	Orbiter	12.0	0.72	0.77	1.08	5.62	1.36	6.43
Carmenita	Orchardale	12.0	0.51	0.70	0.76	4.38	1.14	5.36
Rolling Hills	Orchid	4.16	0.04	0.06	0.04	0.73	0.07	1.04
Locust	Oregon	4.16	0.10	0.14	0.14	0.77	0.18	0.88
Talbert	Oriole	12.0	1.03	1.19	1.58	8.51	2.09	9.49
Lockheed	Orion	16.0	0.07	0.39	-0.23	3.86	0.00	6.86
Broadway	Orizaba	12.0	0.27	0.47	0.39	2.99	0.53	3.47
Naples	Orlena	4.16	0.07	0.20	0.07	1.30	0.09	1.87
Inyokern Town	Orman	4.8	0.00	0.00	0.00	0.02	0.01	0.03
Olympic	Orsatti	4.16	0.14	0.23	0.19	1.26	0.32	1.67
Villa Park	Orvil	12.0	0.63	0.95	0.95	6.17	1.21	6.67
Sunnyside	Osgood	4.16	0.12	0.19	0.18	1.25	0.20	1.50
Delano	Osner	12.0	0.80	1.00	1.22	6.89	1.65	8.62
Ontario	Ostran	4.16	0.11	0.19	0.16	0.99	0.22	1.19
Cudahy	Otis	16.0	1.29	1.59	1.99	9.93	2.57	11.42
Murphy	O'Toole	12.0	0.42	1.02	0.57	5.67	0.72	7.18
Francis	Otter	12.0	0.91	1.12	1.39	6.36	1.88	7.24
Downey	Otto	4.16	0.09	0.07	0.12	0.95	0.14	1.03
Rio Hondo	Ottowa	12.0	1.00	1.15	1.50	6.78	2.04	7.50
Palm Village	Ounce	12.0	0.44	0.56	0.59	2.26	1.39	3.61
Outlaw P.T.	Outlaw	12.0	0.20	0.26	0.30	1.30	0.50	1.52
Victor	Outpost	12.0	0.48	0.49	0.67	3.13	1.21	4.35
Bolsa	Outrigger	12.0	0.19	0.52	0.19	3.74	0.25	5.01
Visalia	Oval	4.16	0.06	0.13	0.09	0.72	0.14	0.88
Calcity 'B'	Overall	12.0	0.25	0.39	0.35	2.01	0.58	2.54
Windsor Hills	Overhill	4.16	0.08	0.18	0.09	1.10	0.12	1.49
Culver	Overland	4.16	0.20	0.28	0.27	1.62	0.43	1.97
Palm Canyon	Overlook	4.16	0.16	0.30	0.22	1.13	0.43	1.75
Corona	Owens	33.0	0.27	0.47	0.44	4.60	0.44	5.60
Mayflower	Owl	4.16	0.06	0.06	0.09	0.71	0.09	0.76
Yukon	Oxford	4.16	0.10	0.14	0.16	0.98	0.16	1.08
Garfield	Oxley	4.16	0.08	0.18	0.05	0.83	0.13	1.43
Cabrillo	Oxy	12.0	0.97	1.31	1.51	7.59	1.69	8.18
Manhattan	Ozone	4.16	0.02	0.34	0.01	0.92	0.02	2.08
Seabright	P&G	12.0	0.05	0.09	0.08	0.53	0.10	0.61
Bowl	Pablo	12.0	0.54	1.03	0.72	6.05	0.94	7.15
Pachappa	Pachappa	4.16	0.02	0.04	0.03	0.24	0.04	0.27
Mayberry	Pachea	12.0	0.45	0.77	0.63	3.83	1.09	5.30
Jefferson	Pacifica	12.0	0.36	0.70	0.54	4.02	0.79	5.07
Vera	Packard	12.0	1.02	1.23	1.54	7.41	1.93	8.41
Rector	Packwood	12.0	0.31	0.92	0.40	4.22	0.79	6.47
Howard	Pacoma	4.16	0.11	0.17	0.15	1.19	0.18	1.42
Stoddard	Pactel	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Anita	Paddock	16.0	0.53	1.12	0.78	6.95	1.01	8.69
Palmdale	Paddy	12.0	0.36	0.59	0.41	3.04	0.67	4.31
Live Oak	Padova	12.0	0.42	0.53	0.49	2.84	1.37	4.84
Santa Barbara	Padre	16.0	1.26	2.30	1.80	10.75	2.60	12.04
Gaviota	Pago	16.0	0.00	0.00	0.00	0.00	0.00	0.00
Pahrump P.T.	Pahrump	25.0	0.00	0.13	0.01	3.22	0.01	6.57
Apple Valley	Pahute	12.0	0.68	0.90	0.98	4.41	1.78	5.83
Tulare	Paige	12.0	0.46	1.00	0.60	4.05	1.09	5.76
Palmdale	Paint	12.0	0.42	0.76	0.55	4.18	0.86	5.98
Painted Cave P.T.	Paintedcave	2.4	0.01	0.02	0.01	0.12	0.01	0.16

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Santa Fe Springs	Painter	12.0	0.85	1.37	1.26	7.93	1.48	9.05
O'neill	Pajaro	12.0	0.17	0.42	0.18	2.76	0.25	3.65
Auld	Pala	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Chase	Palace	12.0	0.58	0.87	0.91	5.81	1.16	6.61
San Vicente	Palisades	4.16	0.02	0.07	0.04	0.37	0.04	0.37
Rush	Paljay	16.0	0.50	0.91	0.74	5.66	0.91	6.48
Arch Beach	Pallette	4.16	0.00	0.02	-0.02	0.31	-0.02	0.53
Moneta	Palm	4.16	0.23	0.35	0.28	1.78	0.44	2.12
Indian Wells	Palmcity	12.0	0.53	0.65	1.13	4.55	2.00	6.01
Live Oak	Palmer	12.0	0.56	0.91	0.70	3.51	1.92	6.27
Chino	Palmetto	12.0	0.55	1.07	0.75	5.64	1.22	7.96
Garnet	Palmview	33.0	0.00	0.00	0.00	0.03	0.01	0.03
Tamarisk	Palobrea	12.0	0.58	0.82	0.93	5.89	1.07	8.07
Eaton	Paloma	16.0	0.09	0.21	0.11	1.25	0.15	1.59
Lynwood	Palomar	4.16	0.09	0.16	0.12	1.00	0.14	1.09
Auld	Palomino	12.0	0.28	0.59	0.36	3.43	0.61	4.95
Potrero	Pampas	16.0	0.81	0.93	1.20	5.26	1.82	6.25
Ely	Panama	12.0	0.56	0.68	0.81	4.15	1.23	5.41
Cameron	Panamerican	12.0	0.32	0.81	0.52	4.82	0.53	5.06
Culver	Pancake	4.16	0.08	0.02	0.08	0.62	0.19	0.94
Panchito P.T.	Panchito	4.16	0.00	0.00	0.00	0.01	0.00	0.01
Camarillo	Pancho	16.0	0.67	0.83	0.97	6.19	1.24	7.25
Proctor	Pandora	12.0	0.62	1.22	0.95	8.10	1.06	12.06
Downey	Pangborn	4.16	0.08	0.13	0.11	0.84	0.16	1.06
Diamond Bar	Panhandle	12.0	0.21	0.24	0.24	1.46	0.67	2.43
Sharon	Panorama	4.16	0.04	0.14	0.00	0.85	0.05	1.44
Fairfax	Panpacific	16.0	0.85	1.06	1.41	6.18	1.86	6.98
Rolling Hills	Pansy	4.16	0.08	0.09	0.06	0.89	0.11	1.14
Lampson	Panther	12.0	0.53	1.22	0.85	6.94	0.90	7.09
Papaya P.T.	Papaya	4.16	0.04	0.10	0.07	0.46	0.10	0.61
Pioneer	Papoose	12.0	0.37	0.47	0.56	2.49	0.80	2.90
Randsburg	Pappas	33.0	0.00	0.01	0.01	0.02	0.01	0.03
Par P.T.	Par	2.4	0.00	0.00	0.00	0.01	0.00	0.01
Valdez	Paradise	16.0	0.39	0.64	0.46	2.31	1.11	4.14
Cudahy	Parafine	16.0	0.46	0.54	0.68	2.89	1.08	3.56
Downey	Paramount	4.16	0.11	0.13	0.15	0.69	0.35	0.97
Pechanga	Parcela	12.0	0.24	0.56	0.27	2.81	0.61	4.65
Ganesha	Parcells	12.0	0.43	0.55	0.68	3.51	0.83	3.85
Glen Avon	Parco	12.0	0.44	0.61	0.60	2.63	1.29	3.66
Padua	Parina	12.0	0.74	1.24	1.04	6.18	1.90	8.57
Del Rosa	Parkdale	12.0	0.37	0.73	0.55	3.67	0.74	4.24
Valdez	Parkmore	16.0	1.10	1.61	1.40	6.32	3.70	11.25
Corona	Parkridge	12.0	0.43	0.67	0.63	3.79	0.95	4.74
Peyton	Parkway	12.0	0.19	0.08	0.19	1.76	0.54	2.74
Stadium	Parma	12.0	0.18	1.31	0.23	4.40	0.26	7.85
Colorado	Parman	16.0	0.44	1.06	0.56	6.64	0.66	8.28
Sunny Dunes	Parocela	4.16	0.12	0.19	0.17	0.71	0.34	1.12
Talbert	Parrot	12.0	0.82	1.03	1.26	6.40	1.72	7.22
Cajalco	Parsons	12.0	0.14	0.32	0.14	1.46	0.39	2.66
Edinger	Parton	4.16	0.10	0.15	0.13	1.20	0.14	1.38
Allen	Pasaglen	4.16	0.00	0.04	-0.02	0.40	-0.02	0.65
Pechanga	Pascal	12.0	0.35	0.82	0.42	4.26	0.85	6.63
Greenhorn	Pascoe	2.4	0.02	0.05	0.03	0.27	0.05	0.33
Corona	Paseo	12.0	0.44	0.76	0.62	5.33	0.76	6.21
Washington	Pass	12.0	0.89	1.22	1.38	6.61	1.66	7.15
Repetto	Pat	16.0	0.85	1.49	1.26	9.80	1.50	10.77
Francis	Pate	12.0	0.94	1.13	1.43	6.60	1.89	7.46
Thornhill	Patencio	12.0	0.81	1.25	1.25	6.49	1.50	7.78
Culver	Pathe	16.0	0.20	0.48	0.27	3.33	0.30	3.56
Tortilla	Patio	12.0	0.37	0.74	0.55	4.01	0.69	4.58
Ojai	Patricia	16.0	0.71	0.90	0.86	4.70	1.61	6.78
Newbury	Patriot	16.0	0.45	0.78	0.54	5.95	0.70	7.83
Milliken	Patron	12.0	1.19	1.49	1.82	7.75	2.36	8.86
Bullis	Pattie	4.16	0.11	0.19	0.16	1.18	0.18	1.33
Sawtelle	Patton	16.0	1.47	2.47	5.01	11.52	12.82	23.12
Brookhurst	Paul	12.0	0.40	0.38	0.56	2.91	0.88	3.59
Three Rivers	Pawley	12.0	0.23	0.48	0.29	2.16	0.41	3.10
Gavilan (115)	Pawnee	12.0	0.59	1.32	0.83	5.92	1.37	8.47
Amargo	Paxton	4.16	0.07	0.13	0.09	0.59	0.14	0.74

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Bradbury	Payne	16.0	0.59	1.46	0.78	7.57	1.04	9.51
Hathaway	Peabody	4.16	0.07	0.16	0.04	1.14	0.10	1.70
Parkwood	Peabush	12.0	0.28	0.64	0.39	3.08	0.54	3.46
Fernwood	Peach	16.0	0.63	0.82	0.98	5.32	1.24	5.95
Peacock U.G.S.	Peacock	4.16	0.01	0.04	0.00	0.27	0.00	0.48
Peacor P.T.	Peacor	12.0	0.06	0.15	0.09	0.78	0.10	0.97
Chestnut	Peanut	12.0	0.67	1.23	1.02	7.30	1.26	8.28
Citrus	Pear	12.0	1.03	1.29	1.48	5.84	2.76	7.94
Pierpont	Pearce	4.16	0.01	0.03	-0.01	0.48	-0.01	0.66
Cabrillo	Pearcy	12.0	0.61	1.35	0.77	10.57	0.90	11.41
Palmdale	Pearland	12.0	0.51	0.68	0.74	4.01	1.21	5.26
Padua	Pebble	12.0	0.45	0.69	0.65	4.30	0.97	5.32
Chestnut	Pecan	12.0	0.60	1.08	0.92	6.87	1.12	7.69
Rush	Peck	16.0	0.55	1.14	0.72	6.12	1.04	7.51
Rio Hondo	Pecos	12.0	0.74	0.85	1.07	4.47	1.75	5.41
Whipple	Peddler	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Pedestrian P.T.	Pedestrian	4.16	0.10	0.19	0.14	1.06	0.18	1.20
San Miguel	Pedro	16.0	1.02	1.28	1.57	6.85	2.15	7.48
Beverly	Peerless	4.16	0.18	0.24	0.27	1.30	0.40	1.56
Moulton	Pekingese	12.0	0.18	0.34	0.25	2.46	0.27	2.83
Talbert	Pelican	12.0	0.64	0.93	1.02	6.44	1.11	6.87
Center	Pellet	12.0	1.01	1.37	1.53	7.33	1.86	8.21
Anaverde	Pelona	12.0	0.20	0.41	0.30	1.99	0.42	2.77
Washington	Penalty	12.0	0.49	0.88	0.71	4.91	1.02	5.86
Santiago	Pence	12.0	0.20	0.38	0.17	3.91	0.27	4.97
Highland	Pencil	12.0	0.60	0.96	0.87	5.05	1.37	6.37
Yucaipa	Pendleton	12.0	0.38	0.57	0.54	3.23	0.87	4.10
El Nido	Penguin	16.0	0.93	1.39	1.51	8.24	1.53	8.28
Crown	Peninsula	12.0	0.59	1.22	0.82	6.29	1.26	8.30
La Habra	Penmar	12.0	1.06	1.51	3.39	6.64	8.91	14.61
Fremont	Penrose	16.0	2.90	4.27	7.31	23.04	15.98	38.96
Aqueduct	Penstock	12.0	0.38	0.61	0.54	3.60	0.78	4.95
Brighton	Penthouse	16.0	1.37	1.64	2.14	12.95	2.65	15.52
Hanford	Peoples	12.0	0.80	1.19	1.23	6.49	1.59	7.90
Atwood	Peralta	12.0	0.34	0.56	0.49	3.11	0.80	4.04
Bayside	Perch	12.0	0.60	0.98	0.88	5.81	0.99	6.40
Timberwine	Perimeter	12.0	0.13	0.24	0.20	1.19	0.23	1.46
Gallatin	Perkins	12.0	0.63	0.81	0.91	4.00	1.40	4.93
Perris P.T.	Perris	12.0	0.16	0.31	0.23	1.46	0.33	1.81
Arro	Pershing	4.16	0.09	0.18	0.13	1.00	0.19	1.32
Modena	Persia	12.0	0.55	1.09	0.80	6.13	1.09	7.41
Tortilla	Peso	12.0	0.49	0.99	0.72	4.98	0.92	5.95
Piute	Petan	12.0	0.36	0.53	0.51	2.85	0.82	3.95
Telegraph	Pete	12.0	0.60	0.76	0.82	4.02	1.76	5.64
Roadway	Peterbilt	12.0	0.56	0.70	0.89	4.90	1.01	5.67
Wakefield	Petit	16.0	0.10	0.18	0.13	0.75	0.20	0.96
Bassett	Petri	12.0	0.82	0.96	1.17	5.51	1.84	6.90
La Fresa	Petrol	16.0	0.61	0.72	0.97	5.12	1.12	5.30
Timoteo	Pettis	12.0	0.29	0.54	0.43	3.10	0.55	3.59
Pheasant P.T.	Pheasant	12.0	0.03	0.10	0.04	0.40	0.06	0.67
Lancaster	Phillips	12.0	0.59	0.78	0.90	4.04	1.22	4.70
Parkwood	Phoenix	12.0	0.16	0.42	0.17	2.67	0.22	3.74
Santa Rosa	Physician	12.0	0.72	0.91	1.16	5.17	1.24	5.28
Niguel	Piano	12.0	0.26	0.72	0.29	4.56	0.38	5.96
Mesa	Picador	16.0	0.74	1.00	1.04	6.63	1.57	8.00
Niguel	Piccolo	12.0	0.60	1.15	0.94	7.24	1.02	7.53
Acton	Pick	12.0	0.54	0.82	0.74	4.14	1.31	6.09
La Canada	Pickens	16.0	0.14	0.28	0.19	1.43	0.27	1.72
Santa Monica	Pickering	4.16	0.11	0.21	0.15	0.88	0.26	1.05
Bridgeport	Picklemeadows	16.0	0.07	0.14	0.11	0.75	0.14	0.82
Pauba	Piconi	12.0	0.64	0.84	0.86	4.27	1.99	6.27
Fair Oaks	Piedmont	4.16	0.22	0.25	0.25	0.85	0.67	1.61
Newcomb	Piedra	12.0	0.07	0.07	0.08	0.65	0.13	0.80
Garnet	Pierson	33.0	0.01	0.02	0.02	0.18	0.02	0.21
Stadler	Pigskin	12.0	0.63	1.27	0.94	6.87	1.18	7.55
Bayside	Pike	12.0	0.53	0.89	0.75	5.11	1.11	6.08
Arcadia	Pilgrim	16.0	0.52	1.20	0.84	7.00	0.88	7.26
Pico	Pilot	12.0	0.04	0.09	0.06	1.25	0.07	2.24
Lunada	Pima	4.16	-0.02	-0.02	-0.06	0.25	-0.06	0.43

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Citrus	Pineapple	12.0	0.62	0.99	0.83	4.59	1.75	6.80
Idyllwild	Pinecove	12.0	0.15	0.29	0.23	1.86	0.27	2.17
Brewster	Pinehurst	4.16	0.17	0.25	0.24	1.67	0.33	1.92
Cajalco	Pinewood	12.0	0.45	0.84	0.65	4.59	1.03	6.20
Orange	Pink	12.0	1.04	1.66	1.59	11.66	1.91	12.95
Johanna	Pinochle	12.0	0.42	0.80	0.65	5.05	0.77	5.81
Chestnut	Pinon	12.0	0.39	0.64	0.53	3.10	0.84	3.77
Lighthipe	Pint	12.0	0.37	0.45	0.56	2.72	0.77	3.00
Hi Desert	Pinto	33.0	0.02	0.03	0.03	0.21	0.03	0.21
Northwind	Pinwheel	12.0	0.00	0.00	0.00	0.03	0.00	0.04
Rolling Hills	Pinzon	16.0	0.06	0.15	0.02	1.61	0.05	1.99
Yucca	Pioneertown	12.0	0.48	0.78	0.68	3.81	0.99	5.17
Olinda	Pipeline	12.0	0.21	0.55	0.27	2.97	0.35	4.15
Santa Rosa	Piper	12.0	0.69	1.23	1.06	6.04	1.22	7.00
Cudahy	Pirate	16.0	1.21	1.58	1.86	9.31	2.48	10.67
Estrella	Pisces	12.0	1.06	2.67	1.72	17.72	1.75	20.56
Chestnut	Pistachio	12.0	1.18	1.81	2.60	11.37	5.18	15.94
Concho	Pistola	12.0	0.85	1.32	1.24	5.82	2.15	8.25
Ditmar	Piston	16.0	0.57	1.36	0.79	8.32	1.04	10.82
Rio Hondo	Pit	16.0	0.01	0.01	0.01	0.03	0.02	0.05
San Antonio	Pitzer	12.0	0.39	0.71	0.50	3.84	0.81	4.86
Pioneer	Piuma	4.16	0.11	0.14	0.13	1.12	0.23	1.46
Trophy	Place	12.0	0.95	1.26	1.49	6.72	2.48	8.55
Saugus	Placerita	16.0	1.14	1.78	1.68	9.36	2.33	12.19
Timoteo	Placid	12.0	0.56	1.15	0.80	5.51	1.19	7.02
Porterville	Plano	12.0	0.85	1.18	1.21	5.16	1.84	6.67
Sun City	Plasma	12.0	0.15	0.31	0.19	1.81	0.34	2.57
Crater	Plateau	16.0	0.76	1.20	1.02	6.71	1.78	8.85
Limestone	Platinum	12.0	0.67	1.17	1.01	7.30	1.29	8.16
Firehouse	Platoon	12.0	0.60	0.97	0.89	6.12	1.26	7.45
Brewster	Platt	4.16	0.08	0.13	0.12	0.85	0.16	0.94
Beverly	Playboy	16.0	0.53	1.16	0.79	6.06	1.04	7.30
Eisenhower	Player	33.0	0.66	0.84	1.06	4.86	1.09	4.98
Moraga	Playhouse	12.0	0.72	1.29	1.06	8.60	1.42	10.85
Plaza P.T.	Plaza	4.16	0.01	0.01	0.01	0.06	0.02	0.11
Athens	Plum	4.16	0.16	0.22	0.23	1.33	0.27	1.50
Tamarisk	Plumley	12.0	0.37	0.46	0.54	2.34	0.86	2.98
Cajalco	Plummer	12.0	0.79	1.04	1.23	6.72	1.57	8.26
Atwood	Plumosa	12.0	0.29	0.57	0.38	3.28	0.65	4.67
Bluff Cove	Pluto	4.16	-0.02	-0.05	-0.09	0.39	-0.08	0.61
Inglewood	Plymouth	4.16	0.21	0.34	0.28	1.91	0.38	2.26
La Palma	Pocket	12.0	0.05	0.13	0.06	0.91	0.06	1.14
Tortilla	Poco	33.0	0.00	0.01	0.00	0.02	0.01	0.04
Trona	Pointofrocks	12.0	0.04	0.12	0.06	0.89	0.08	1.17
Johanna	Poker	12.0	0.84	1.32	1.29	9.38	1.55	10.66
Barstow	Police	12.0	0.49	0.79	0.72	3.93	1.17	4.57
Wave	Polk	12.0	0.36	0.76	0.27	6.82	0.44	8.53
Fairview	Pollard	12.0	0.51	0.95	0.78	5.65	0.94	6.20
Santa Rosa	Polo	12.0	0.94	1.22	1.39	5.39	1.95	6.36
Temescal P.T.	Polymer	12.0	0.01	-0.09	0.00	0.00	0.03	0.02
Francis	Pomall	12.0	1.00	1.18	1.49	6.64	2.17	7.80
Terrace	Pomeroy	4.16	0.08	0.11	0.11	1.00	0.12	1.12
Browning	Pond	12.0	0.15	0.21	0.22	1.18	0.30	1.36
Colonia	Ponderosa	16.0	2.67	2.84	3.60	12.14	8.71	18.66
Vera	Pontiac	12.0	1.00	1.21	1.48	7.61	2.07	9.05
Auld	Pony	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Moulton	Poodle	12.0	0.53	1.02	0.82	6.15	0.92	6.52
West Barstow	Pool	4.16	0.06	0.07	0.09	0.40	0.12	0.46
Cabazon	Poppetflats	12.0	0.18	0.22	0.34	1.61	0.50	2.03
Sunnyside	Poppy	12.0	0.51	0.58	0.66	2.71	1.48	4.15
Temescal P.T.	Porcelain	4.16	0.06	0.11	0.08	0.33	0.21	0.60
Kempster	Porker	4.16	0.01	0.01	0.01	0.06	0.01	0.06
Corona	Porphyry	33.0	0.04	0.07	0.06	0.63	0.07	0.79
Delano	Port	12.0	0.89	1.06	1.37	6.61	1.67	7.66
Victor	Portland	33.0	0.72	0.92	1.17	7.51	1.18	8.33
Palm Village	Portola	4.8	0.15	0.24	0.21	0.90	0.42	1.44
Portuguese Bend P.T.	Portuguesebend	4.16	0.01	0.01	0.01	0.11	0.02	0.18
Proctor	Poseidon	12.0	0.73	1.01	1.14	6.76	1.35	10.24
Poso Park P.T.	Posopark	2.4	0.00	0.00	0.00	0.02	0.00	0.02

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Trona	Potash	12.0	0.08	0.14	0.11	0.54	0.18	0.70
Sixteenth Street	Potato	12.0	0.40	0.73	0.59	3.61	0.86	4.28
Lathrop Wells P.T.	Potosi	25.0	0.03	0.04	0.03	0.05	0.07	0.13
Elsinore	Pottery	12.0	0.65	0.94	0.86	3.81	1.53	5.09
Yucaipa	Poultry	12.0	0.59	0.88	0.83	5.35	1.49	7.17
Palm Village	Pound	12.0	0.97	1.17	1.42	4.90	2.30	6.10
Auld	Pourroy	12.0	0.20	0.44	0.28	2.33	0.42	3.18
Rio Hondo	Powder	16.0	0.54	0.83	0.76	4.84	1.10	5.54
Newhall	Powell	16.0	0.66	1.41	0.86	6.73	1.50	9.55
Muscoy	Power	4.16	0.14	0.26	0.22	1.45	0.22	1.77
Potrero	Prado	16.0	1.14	1.48	1.81	8.15	2.02	8.49
Strathmore	Prairie	12.0	0.18	0.36	0.22	1.52	0.38	2.04
Woodville	Pratt	12.0	0.12	0.16	0.17	0.90	0.27	1.14
Savage	Prayer	12.0	0.23	0.92	0.31	4.21	0.35	6.60
Stetson	Predator	12.0	0.31	0.57	0.47	3.51	0.60	4.07
Padua	Prego	12.0	0.83	1.05	1.07	4.67	2.88	7.71
Cornuta	President	12.0	0.84	1.12	1.22	5.70	1.93	6.85
Newcomb	Presley	12.0	0.36	0.72	0.53	4.19	0.69	5.01
Colton	Preston	12.0	0.30	0.67	0.42	3.33	0.69	4.84
Corona	Price	12.0	0.60	1.15	0.91	6.99	1.11	8.80
Cypress	Prida	12.0	0.26	0.34	0.39	2.10	0.48	2.38
Viejo	Primero	12.0	0.33	0.65	0.44	3.95	0.65	4.97
Bradbury	Primrose	16.0	0.84	1.51	1.17	9.50	1.69	11.89
Calden	Prince	16.0	0.07	0.12	0.10	0.64	0.14	0.76
Gage	Priory	4.16	0.05	0.07	0.08	0.48	0.08	0.51
Basta	Pritchard	4.16	0.06	0.12	0.08	0.86	0.09	1.03
Parkwood	Privet	12.0	0.34	0.77	0.47	4.25	0.59	5.30
Santa Rosa	Probst	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Narod	Products	12.0	0.34	0.55	0.47	2.61	0.76	3.25
Isla Vista	Professor	16.0	1.17	1.94	1.86	13.61	1.99	13.84
Pedley	Profit	12.0	0.83	0.97	1.14	4.40	2.56	6.35
Corona	Promenade	12.0	1.25	1.63	1.98	10.90	2.22	12.56
Del Sur	Pronghorn	12.0	0.46	0.55	0.68	3.09	1.10	3.63
Naples	Prospect	4.16	0.10	0.17	0.13	1.31	0.15	1.65
Pruitt P.T.	Pruitt	4.16	0.04	0.10	0.05	0.38	0.08	0.50
Parkwood	Prune	12.0	0.47	0.83	0.68	4.71	1.07	6.01
Exeter	Prunner	4.16	0.01	0.02	0.02	0.02	0.06	0.07
Etiwanda	Pryor	12.0	0.41	0.69	0.58	3.50	1.09	4.86
Layfair	Puddingstone	12.0	0.64	1.33	0.99	7.64	1.18	8.52
La Fresa	Pueblo	16.0	0.28	0.47	0.37	2.63	0.51	3.00
Modoc	Puesta	4.16	-0.02	0.01	-0.10	0.81	-0.10	1.23
Corona	Pulaski	12.0	0.88	1.29	2.16	8.84	4.64	13.66
Ditmar	Pullman	4.16	0.09	-0.08	0.02	1.37	0.06	1.70
Fruitland	Pulp	16.0	0.51	0.62	0.77	3.50	1.10	4.01
Del Rosa	Pumalo	12.0	0.18	0.40	0.27	2.08	0.31	2.55
Chiquita	Punch	12.0	0.09	0.12	0.00	2.68	0.05	3.54
Washington	Punt	12.0	0.39	0.51	0.60	3.27	0.67	3.49
Outlet P.T.	Purchase	12.0	0.43	0.53	0.67	3.07	0.80	3.26
Sawtelle	Purdue	16.0	0.37	0.55	0.52	4.00	0.68	4.45
Cudahy	Purex	16.0	0.31	0.41	0.47	2.07	0.69	2.53
Orange	Purple	12.0	0.47	0.76	0.62	3.22	1.10	4.30
San Gabriel	Putney	4.16	0.10	0.17	0.14	1.08	0.20	1.29
Gilbert	Putter	12.0	0.52	0.85	0.76	5.16	1.07	6.24
Wakefield	Pyle	16.0	0.46	0.61	0.70	3.97	0.98	4.46
Savage	Pyramid	12.0	0.65	0.92	0.98	5.19	1.37	6.36
Parkwood	Pyrus	12.0	0.29	0.62	0.37	3.16	0.66	4.61
North Oaks	Python	16.0	0.60	1.41	0.79	6.41	1.44	9.49
Modena	Qatar	12.0	0.13	0.60	0.06	3.53	0.17	5.96
Tipton	Quail	12.0	0.39	0.50	0.60	4.16	0.82	5.56
Layfair	Quaker	4.16	0.08	0.12	0.11	0.66	0.24	1.00
Pedley	Quarry	12.0	0.34	0.82	0.42	3.74	0.93	6.33
Palm Village	Quart	12.0	0.72	0.87	1.06	4.11	1.73	5.10
Placentia	Quarter	12.0	0.30	0.61	0.47	3.63	0.51	3.80
Stadler	Quarterback	12.0	0.26	0.66	0.36	3.50	0.46	4.62
Limestone	Quartz	12.0	0.53	0.87	0.78	4.82	1.04	5.31
Sun City	Quasar	12.0	0.14	0.29	0.18	1.48	0.32	2.11
Imperial	Quebec	4.16	0.12	0.14	0.15	1.03	0.20	1.23
Inglewood	Queen	4.16	0.05	0.09	0.07	0.43	0.09	0.51
Queen Mary U.G.S.	Queenmary1	4.16	0.12	0.21	0.19	1.20	0.20	1.22

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Lancaster	Queensland	12.0	0.47	0.74	0.70	4.14	1.04	5.34
Crest	Quicksilver	16.0	0.19	0.67	0.11	3.39	0.26	5.66
Anaverde	Quinby	12.0	0.92	1.24	1.37	6.16	2.00	7.30
Broadway	Quincy	4.16	0.10	0.17	0.14	1.08	0.16	1.24
Soquel	Quinto	12.0	0.56	0.83	0.76	5.08	1.46	7.10
Southwind	Quixote	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Lucerne	Rabbit	12.0	0.30	0.42	0.37	1.46	0.64	2.02
North Oaks	Racer	16.0	0.10	0.19	0.09	1.23	0.24	1.94
Trophy	Raceway	12.0	1.41	1.82	2.26	11.28	2.39	12.72
Villa Park	Racine	12.0	1.34	1.62	2.02	9.69	2.98	10.77
Holiday	Racquetclub	4.16	0.04	0.05	0.13	0.49	0.30	0.80
Villa Park	Radec	12.0	0.76	0.91	1.17	6.00	1.58	6.48
Cypress	Radford	12.0	0.47	0.64	0.72	3.95	0.87	4.48
La Fresa	Radiator	16.0	0.02	-0.01	0.02	0.11	0.08	0.18
Cherry	Radium	12.0	0.19	0.37	0.29	2.20	0.34	2.55
Delano	Radnor	12.0	0.92	1.34	1.40	8.03	1.69	9.40
Cucamonga	Rahal	12.0	0.40	0.76	0.60	4.71	0.72	5.53
Carson	Rahn	16.0	0.73	1.03	1.17	7.68	1.30	8.87
Slater	Raiders	12.0	0.25	0.61	0.29	4.86	0.36	6.24
Somis	Rainbow	16.0	0.47	0.58	0.68	3.63	1.16	4.33
Sixteenth Street	Raisin	12.0	0.41	0.94	0.59	4.84	0.73	5.59
San Marino	Raleigh	4.16	0.10	0.19	0.13	0.89	0.28	1.41
Wabash	Ralston	16.0	0.16	0.31	0.24	1.71	0.31	1.90
Estero	Ramac	16.0	0.49	0.58	0.74	4.07	0.98	4.44
Vera	Rambler	12.0	0.72	0.86	1.07	4.63	1.51	5.40
Bunker	Rambo	12.0	0.40	0.72	0.61	3.87	0.96	4.98
Stadium	Ramp	12.0	0.53	1.25	0.82	8.20	0.93	9.60
Slater	Rams	12.0	0.83	1.20	1.20	6.87	1.87	8.80
Ganesha	Ramsey	4.16	0.08	0.10	0.11	0.50	0.18	0.64
Chase	Ramsgate	12.0	0.56	0.84	0.68	3.85	1.93	6.96
Farrell	Rana	12.0	0.76	1.01	1.03	4.12	2.45	6.70
O'neill	Ranch	12.0	0.43	0.75	0.60	4.47	0.86	5.15
Rancheria P.T.	Rancheria	2.4	0.00	0.00	0.00	0.01	0.00	0.01
Santiago	Rand	12.0	0.56	1.10	0.89	6.87	0.94	7.35
Ranger P.T.	Ranger	2.4	0.03	0.05	0.05	0.34	0.05	0.37
Maraschino	Ranier	12.0	-0.10	-0.26	-0.31	0.52	-0.28	1.05
Walker Basin	Rankin	12.0	0.02	0.04	0.02	0.12	0.04	0.20
Belmont	Ransom	4.16	0.12	0.20	0.16	1.09	0.22	1.33
Sunny Dunes	Rapfeal	4.16	0.15	0.22	0.22	0.98	0.36	1.31
Harper Lake	Raptor	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Oak Grove	Rasmussen	12.0	0.38	0.87	0.60	6.04	0.65	6.32
Sunnyside	Raton	4.16	0.07	0.10	0.06	0.95	0.08	1.30
North Oaks	Rattler	16.0	0.17	0.22	0.07	2.20	0.26	3.11
Talbert	Raven	12.0	0.77	0.96	1.16	5.95	1.64	6.85
Cypress	Ravenna	12.0	0.44	0.61	0.66	3.76	0.80	4.17
Arroyo	Ravine	16.0	0.57	1.35	0.76	6.46	1.32	9.17
Auld	Rawson	12.0	0.01	-0.02	-0.01	0.47	0.00	0.54
Fullerton	Raybestos	12.0	0.63	1.15	0.98	7.43	1.11	7.77
Bullis	Rayborn	4.16	0.18	0.29	0.27	1.71	0.31	1.97
Anaverde	Rayburn	12.0	0.34	0.45	0.43	2.56	0.81	3.70
Palmdale	Razor	12.0	0.32	0.45	0.44	2.64	0.70	3.52
San Miguel	Ready	16.0	1.30	1.94	1.86	8.79	2.97	10.19
Alessandro	Reagan	12.0	0.27	0.50	0.38	2.50	0.58	3.15
Maxwell	Reakes	12.0	0.17	0.27	0.23	2.05	0.32	2.59
Fremont	Reasoner	16.0	0.91	1.22	1.42	9.74	1.74	11.76
Bedford	Rebel	4.16	0.09	0.30	0.13	1.14	0.14	1.82
Maxwell	Reche	12.0	0.50	0.90	0.72	4.42	1.10	5.45
Orange	Red	12.0	0.59	0.92	0.87	5.89	1.12	6.56
Bloomington	Redball	12.0	0.49	0.96	0.78	7.02	0.84	8.76
Venice Hill	Redbanks	12.0	0.70	1.36	0.87	5.87	1.44	7.49
North Muroc	Redbarn	12.0	0.04	0.05	0.06	0.39	0.06	0.52
Red Box	Redbox	16.0	0.01	0.01	0.01	0.07	0.02	0.09
Center	Redflag	12.0	0.42	0.49	0.73	2.42	1.37	3.33
Torrance	Redgum	16.0	0.44	0.66	0.66	3.29	0.92	3.83
Fairview	Redhill	12.0	0.24	0.44	0.36	2.37	0.47	2.65
Stoddard	Redick	4.16	0.03	0.05	0.04	0.24	0.07	0.29
Hanford	Redington	12.0	1.34	1.67	2.54	8.68	4.13	10.44
Milliken	Redlabel	12.0	1.36	2.48	3.84	14.26	8.68	22.61
Casitas	Redmountain	16.0	0.17	0.24	0.30	1.72	0.47	2.02

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Pioneer	Redskin	12.0	0.20	0.25	0.30	1.46	0.39	1.64
Estero	Redstone	16.0	1.18	1.38	1.83	8.76	2.24	9.87
Declez	Redwood	12.0	0.26	0.50	0.40	2.99	0.45	3.62
Mentone	Reed	12.0	0.20	0.30	0.25	2.58	0.33	2.96
Cortez	Reeder	12.0	0.53	0.66	0.71	3.32	1.45	4.98
Larder	Reeves	4.16	0.21	0.27	0.30	1.17	0.46	1.40
Stadler	Referee	12.0	0.35	0.80	0.50	4.08	0.77	5.61
Carmenita	Refoil	12.0	0.79	1.07	1.17	6.71	1.78	8.41
Cameron	Regal	12.0	0.25	0.51	0.34	2.66	0.45	3.10
San Vicente	Regent	4.16	-0.01	0.18	-0.06	0.54	-0.06	1.49
Rivera	Regina	4.16	0.14	0.20	0.20	1.41	0.31	1.69
Colonia	Reimann	16.0	0.62	0.74	0.90	4.13	1.36	5.40
Silver Spur	Rein	12.0	0.48	1.04	0.68	4.12	1.10	6.47
Pepper	Reisling	12.0	0.33	0.93	0.44	2.97	0.92	5.27
Royal	Rejada	16.0	1.01	1.68	1.48	10.56	1.97	12.57
Vail	Relief	16.0	0.10	0.13	0.15	0.82	0.18	0.96
Merced	Relish	12.0	1.04	1.32	1.55	6.86	2.43	8.28
Barstow	Remote	33.0	0.02	0.04	0.03	0.19	0.05	0.25
Lennox	Republic	16.0	0.48	0.78	0.69	4.44	0.85	5.03
Nelson	Resort	33.0	0.01	0.01	0.01	0.09	0.01	0.10
Retreat P.T.	Retreat	12.0	0.16	0.44	0.23	1.59	0.41	2.52
June Lake	Reversepeak	12.0	0.07	0.14	0.10	0.83	0.14	0.99
Imperial	Rex	4.16	0.09	0.08	0.12	0.95	0.19	1.13
Beverly	Rexford	4.16	0.11	0.15	0.17	0.73	0.24	0.81
Cudahy	Rheem	16.0	0.67	0.89	1.08	7.35	1.14	8.68
Rio Hondo	Rhine	12.0	0.88	1.03	1.36	6.56	1.73	7.06
San Dimas	Rhoads	12.0	0.36	0.55	0.53	2.64	0.75	3.31
Crater	Rhoda	16.0	0.53	0.93	0.78	5.60	1.18	6.86
Carolina	Rhodeisland	12.0	0.24	0.41	0.36	2.29	0.50	2.59
Brighton	Rhumba	16.0	1.32	1.79	2.02	11.59	2.71	14.53
San Miguel	Ricardo	16.0	0.96	1.08	1.42	6.35	1.72	7.02
Oxnard	Rice	4.16	0.15	0.25	0.20	1.39	0.28	1.56
Costa Mesa	Richards	4.16	0.04	0.06	0.05	0.37	0.06	0.47
Vestal	Richgrove	12.0	0.15	0.20	0.22	1.49	0.28	1.77
Fullerton	Richman	4.16	0.07	0.11	0.10	0.66	0.18	0.95
Richuson P.T.	Richuson	4.16	0.01	0.02	0.01	0.18	0.02	0.22
Edwards	Rickenback	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Parkwood	Ricko	12.0	0.20	0.52	0.17	3.95	0.25	5.40
Inyokern	Rickover	33.0	1.78	2.30	2.90	13.51	2.91	13.75
Gorman	Ridge	12.0	0.42	0.54	0.60	2.15	1.04	2.66
Walteria	Ridgeland	4.16	0.04	0.02	0.00	1.02	0.00	1.35
Newcomb	Ridgemoor	12.0	0.33	0.70	0.46	3.88	0.70	5.25
Vestal	Rieck	12.0	0.17	0.22	0.27	1.71	0.31	1.97
Center	Rifle	12.0	0.15	0.39	0.17	2.30	0.22	3.05
Newmark	Riggin	4.16	0.11	0.12	0.14	1.00	0.25	1.30
Wimbledon	Riggs	12.0	1.08	1.35	2.50	10.32	4.71	15.00
Cardiff	Riley	12.0	0.46	0.61	0.73	3.46	0.85	3.73
Burnt Mill	Rim	12.0	0.41	0.72	0.54	3.26	0.81	3.82
Culver	Rimpau	4.16	0.05	0.06	0.03	0.92	0.05	1.13
Morro	Rimrock	12.0	0.82	1.44	1.17	7.44	1.66	8.48
Rincon P.T.	Rincon	4.16	0.01	0.02	0.01	0.13	0.01	0.19
Saugus	Riner	16.0	0.43	1.17	0.61	6.02	0.64	8.29
Cabrillo	Ringo	12.0	1.04	2.29	1.65	14.08	1.73	14.65
Tulare	Rinker	12.0	0.46	1.01	0.64	5.23	0.97	6.43
Thunderbird	Riodelsol	4.8	0.04	0.07	0.11	0.61	0.22	0.98
Riverway	Riogrande	12.0	0.29	0.60	0.59	5.10	0.97	7.51
Santa Monica	Riptide	16.0	0.81	2.02	1.21	10.43	1.37	12.24
Huntington Park	Rita	4.16	0.30	0.34	0.41	1.11	0.72	1.49
Grangeville	Ritchie	4.16	0.00	0.01	0.00	0.01	0.01	0.04
Anaverde	Ritter	12.0	0.54	0.75	0.85	4.22	0.97	4.64
Casitas	Riva	16.0	0.29	0.66	0.28	4.89	0.37	6.95
Alessandro	Rivard	12.0	0.28	0.32	0.38	1.59	0.78	2.27
Olive Lake	Riverbend	12.0	0.18	0.23	0.30	1.97	0.36	3.17
Bassett	Rivergrade	12.0	0.26	0.34	0.39	2.25	0.56	2.67
Bandini	Riverside	16.0	0.86	1.10	1.32	5.94	1.73	7.06
Second Avenue	Riverview	12.0	0.02	0.02	0.02	0.07	0.05	0.11
Downey	Rives	4.16	0.09	0.08	0.11	0.67	0.25	0.92
Bridge	Rivet	4.16	-0.01	-0.04	-0.08	0.47	-0.07	0.51
Santa Barbara	Riviera	4.16	0.02	0.06	-0.01	0.54	-0.01	0.90

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Cajalco	Roadrunner	12.0	0.23	0.52	0.29	2.79	0.54	4.25
Granada	Roanoke	4.16	0.06	0.18	0.05	0.77	0.19	1.58
Arcadia	Robbie	16.0	0.35	0.77	0.49	4.82	0.57	5.57
Olympic	Robertson	4.16	0.05	0.09	0.07	0.51	0.12	0.66
Wrightwood	Robin	12.0	0.09	0.23	0.13	1.26	0.16	1.36
Randolph	Robinson	16.0	0.29	0.36	0.46	2.19	0.65	2.48
Bridgeport	Robinsoncreek	12.0	0.02	0.02	0.02	0.15	0.03	0.17
State Street	Roble	12.0	0.49	0.86	0.70	4.19	0.98	4.74
Neptune	Rocha	4.16	0.12	0.15	0.17	1.38	0.18	1.60
Kempster	Rochholtz	4.16	0.09	0.19	0.14	1.12	0.19	1.44
San Antonio	Rock	12.0	0.90	1.04	1.38	6.48	1.61	6.80
Sherwin	Rockcreek	12.0	0.01	0.02	0.01	0.18	0.02	0.22
Hedda	Rocket	4.16	0.07	0.06	0.09	0.82	0.11	0.88
Downs	Rockettown	12.0	0.59	0.80	1.00	5.48	1.41	7.19
Walnut	Rockhill	12.0	0.72	0.93	0.89	4.56	2.06	7.82
Elsinore	Rockridge	12.0	0.40	0.79	0.55	4.00	0.84	5.14
Tennessee	Rockwell	12.0	0.30	0.62	0.43	3.51	0.65	4.75
Beverly	Rodeo	4.16	0.24	0.35	0.32	1.39	0.73	2.27
Stewart	Rodney	12.0	0.47	0.62	0.74	3.44	0.87	3.86
Pierpont	Roebuck	4.16	0.11	0.12	0.15	0.95	0.21	1.07
Venida	Roeding	12.0	0.32	0.80	0.38	2.83	0.68	4.45
Terrace	Rogers	4.16	0.06	0.09	0.09	0.71	0.10	0.77
Shandin	Roi-Tan	12.0	0.48	1.05	0.71	6.00	0.86	7.44
Fullerton	Roma	12.0	0.65	1.52	0.97	8.35	1.14	9.16
Haskell	Romanus	16.0	0.20	0.86	0.17	4.11	0.32	7.02
Pechanga	Romero	12.0	0.25	0.56	0.33	2.98	0.58	4.32
MacArthur	Rommel	12.0	0.32	0.70	0.41	4.47	0.51	5.20
Ronnie P.T.	Ronnie	4.16	0.05	0.05	0.07	0.32	0.11	0.36
La Habra	Ronwood	12.0	1.01	1.13	1.61	8.04	1.80	8.29
Redman	Roosevelt	12.0	0.17	0.24	0.24	1.35	0.38	1.98
Moraga	Roripaugh	12.0	1.05	1.32	1.60	6.40	2.21	7.40
Camarillo	Rosa	16.0	0.55	0.15	0.62	6.57	0.76	7.28
Sunnyside	Rose	12.0	0.79	1.05	1.22	6.65	1.43	7.40
Pitman	Rosebud	12.0	0.10	0.16	0.13	0.68	0.19	0.87
Lindsay	Rosedale	12.0	0.30	0.60	0.38	2.65	0.62	3.49
Amador	Roseglen	16.0	0.61	1.05	0.91	6.97	1.16	8.37
Ganesha	Roselawn	12.0	0.70	0.85	1.04	4.72	1.53	5.56
Perry	Rosemary	4.16	0.07	0.05	0.06	0.99	0.07	1.12
La Canada	Rosemont	16.0	0.48	0.97	0.57	4.95	1.09	7.08
Eric	Roseton	12.0	0.73	0.89	1.01	4.32	1.80	5.68
Rialto	Rosewood	4.16	0.05	0.10	0.07	0.54	0.09	0.66
Padua	Rossi	12.0	0.43	0.59	0.61	3.93	0.83	4.61
Cypress	Rossmoor	12.0	0.92	1.28	1.33	7.12	1.81	8.90
Chino	Roswell	12.0	0.85	1.08	1.29	6.68	1.75	8.45
Stetson	Rotec	12.0	0.26	0.66	0.31	4.52	0.38	5.95
Gilbert	Rough	12.0	0.14	0.28	0.23	1.99	0.24	2.21
Corona	Roulette	12.0	0.41	0.71	0.60	4.26	0.78	5.05
Maraschino	Roundel	12.0	0.20	0.44	0.30	2.77	0.33	3.47
Lindsay	Roundvalley	12.0	0.29	0.50	0.41	3.18	0.61	4.08
Devers	Rover	12.0	0.36	0.54	0.59	2.63	1.04	3.67
Running Springs	Rowco	12.0	0.11	0.30	0.18	1.52	0.19	1.82
Maxwell	Rowe	12.0	0.20	0.36	0.30	2.03	0.39	2.35
Anita	Rowland	4.16	0.07	0.08	0.07	0.79	0.13	1.08
Stadium	Roxanne	12.0	0.16	0.40	0.15	2.83	0.21	3.96
Beverly	Roxbury	4.16	0.18	0.26	0.24	1.12	0.54	1.76
Roxie P.T.	Roxie	2.4	0.01	0.01	0.01	0.09	0.02	0.10
Liberty	Royaloaks	12.0	0.81	0.98	1.25	5.03	1.86	6.39
Arroyo	Royce	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Naples	Roycroft	4.16	0.05	0.13	0.04	0.97	0.04	1.45
Fullerton	Royer	12.0	0.77	1.31	1.17	8.14	1.44	8.76
Borrego	Rubin	12.0	0.27	0.62	0.28	4.47	0.38	5.86
Santiago	Ruble	12.0	0.49	0.89	0.73	5.30	0.90	5.85
Limestone	Ruby	12.0	0.27	0.46	0.42	3.25	0.44	3.36
Huntington Park	Rugby	4.16	0.16	0.20	0.24	0.90	0.32	1.01
Smiley	Ruggles	4.16	0.04	0.11	0.04	0.57	0.12	1.06
Fogarty	Ruiz	12.0	0.31	0.69	0.39	3.56	0.75	5.50
Highland	Ruler	12.0	0.32	0.73	0.37	3.60	0.85	6.06
Johanna	Rummy	12.0	0.47	0.74	0.75	5.88	0.81	6.56
Culver	Runway	16.0	0.31	0.55	0.44	3.01	0.62	3.36

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Garvey	Rural	4.16	0.15	0.15	0.20	1.06	0.37	1.34
Victor	Russboyd	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Broadway	Russell	12.0	0.48	0.95	0.67	5.36	0.81	6.65
O'neill	Rustic	12.0	0.25	0.57	0.25	4.00	0.37	5.44
Crown	Rutgers	12.0	0.48	1.45	0.63	6.84	0.73	10.01
La Veta	Ruth	12.0	0.65	1.36	1.02	7.73	1.18	8.13
Brighton	Ruthellen	16.0	0.76	0.90	1.16	5.90	1.59	7.13
Cucamonga	Rutherford	12.0	1.16	1.61	3.57	9.02	8.60	17.03
Villa Park	Rutledge	12.0	0.41	0.85	0.56	4.63	0.73	5.58
Cucamonga	Ruttman	12.0	0.96	1.19	1.50	8.96	1.85	10.42
Lennox	Ryan	16.0	0.84	1.37	1.23	7.65	1.51	8.32
Sixteenth Street	Rye	12.0	0.22	0.67	0.33	3.19	0.36	4.10
Ely	Rzyski	12.0	0.33	0.72	0.39	4.53	0.55	6.04
Hanford	Saber	12.0	0.13	0.12	0.17	0.56	0.32	0.79
Pechanga	Sabino	12.0	0.21	0.50	0.25	2.39	0.53	3.93
Fair Oaks	Sacramento	4.16	0.11	0.15	0.10	0.93	0.27	1.49
Calectric	Sad	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Banning	Saddleback	33.0	0.01	0.01	0.01	0.03	0.02	0.06
Palm Springs	Safeway	4.16	0.10	0.14	0.15	0.61	0.27	0.80
Mt. Vernon	Sage	4.16	0.07	0.12	0.10	0.62	0.13	0.71
Bryman	Sagebrush	4.16	0.00	0.01	0.00	0.02	0.01	0.03
Zack	Sagehen	12.0	0.25	0.45	0.37	3.61	0.44	5.06
Estrella	Sagittarius	12.0	0.30	0.63	0.39	5.00	0.47	6.23
Torrance	Sago	16.0	0.64	1.07	0.85	6.78	1.07	7.98
Tamarisk	Saguaro	12.0	1.19	1.40	1.62	5.71	3.93	9.03
Santa Rosa	Sahara	12.0	1.11	1.44	1.65	6.62	2.69	8.36
Arcadia	Saintjo	16.0	0.57	0.95	1.01	6.94	1.50	9.27
Slater	Saints	12.0	0.27	0.77	0.36	5.08	0.40	6.61
Fairview	Sakioka	12.0	0.34	0.62	0.54	4.10	0.60	4.47
Bedford	Saks	4.16	0.11	0.26	0.15	1.11	0.27	1.64
Sullivan	Salem	4.16	0.09	0.11	0.13	0.84	0.14	0.92
Cudahy	Sales	4.16	0.11	0.15	0.16	1.20	0.18	1.37
El Nido	Salmon	16.0	0.41	0.70	0.56	5.26	0.62	5.78
Iron Mt. (SCE)	Salt	16.0	0.00	0.00	0.00	0.01	0.01	0.01
Three Rivers	Saltcreek	12.0	0.19	0.25	0.31	1.60	0.45	2.14
Cudahy	Saltlake	16.0	0.58	0.78	0.97	4.42	1.44	5.34
San Miguel	Salvador	16.0	0.58	1.07	0.80	7.07	0.94	7.79
Layfair	Sam	12.0	0.75	0.87	1.13	5.07	1.59	5.89
South Gate	Samar	4.16	0.08	0.12	0.10	0.48	0.16	0.61
Wimbledon	Sampras	12.0	0.56	0.74	0.90	5.04	0.97	5.61
Modoc	Sanandreas	4.16	0.09	0.14	0.13	0.93	0.17	1.08
Declez	Sanber	12.0	0.47	0.94	0.71	5.70	0.92	7.12
Fernwood	Sanborn	16.0	0.00	0.00	0.00	0.00	0.00	0.00
Southwind	Sancho	12.0	0.00	0.00	0.00	0.01	0.00	0.01
Solemint	Sandcanyon	16.0	0.41	0.66	0.66	5.37	0.83	7.97
Santa Rosa	Sanddunes	12.0	0.84	1.00	1.41	5.66	2.04	6.88
Randall	Sandell	12.0	0.27	0.52	0.34	3.18	0.62	4.62
Upland	Sanders	4.16	0.10	0.17	0.15	0.92	0.27	1.26
Tahiti	Sandman	16.0	0.49	1.01	0.79	5.89	0.81	6.12
Felton	Sandra	16.0	1.37	1.62	2.13	9.42	2.67	10.29
Bassett	Sandy	12.0	0.62	0.78	0.93	4.46	1.31	5.38
Duarte	Sanitarium	4.16	0.08	0.14	0.12	1.06	0.12	1.29
San Antonio	Sanjose	12.0	0.57	0.70	0.94	3.40	1.38	3.89
Bryan	Sanjuan	12.0	0.37	0.69	0.60	4.36	0.73	4.94
Bartolo	Sanka	4.16	0.10	0.14	0.14	0.93	0.22	1.12
Casitas	Sannicholas	16.0	0.82	1.17	1.38	7.90	1.83	9.75
San Marino	Sanpasqual	4.16	0.10	0.13	0.15	1.21	0.16	1.82
Garnet	Sanrafael	12.0	0.44	0.56	0.85	4.08	1.33	5.34
Cardiff	Santaanariverno.1-No.3	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Hi Desert	Santana	33.0	0.00	0.01	0.01	0.04	0.01	0.05
Padua	Santorini	12.0	0.19	0.12	0.23	3.09	0.25	3.40
San Ysidro P.T.	Sanysisdro	2.4	0.00	0.00	0.00	0.00	0.00	0.00
Upland	Sapphire	12.0	0.58	1.00	0.84	5.27	1.44	7.05
Jefferson	Sapporo	12.0	0.27	0.51	0.40	3.14	0.55	4.00
Ramona	Sarah	4.16	0.15	0.15	0.22	1.17	0.30	1.33
Levy	Saratoga	16.0	0.96	1.23	1.51	9.24	1.88	11.76
Octol	Sargent	12.0	0.52	0.62	0.81	4.98	1.02	6.20
Broadway	Sassoon	12.0	0.37	1.03	0.55	6.27	0.65	7.29
San Antonio	Satellite	12.0	0.77	1.45	1.12	8.08	1.51	9.43

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Randolph	Saturn	16.0	0.26	0.34	0.39	1.81	0.50	2.13
Thornhill	Saturnino	12.0	0.50	0.65	0.77	3.53	0.97	4.06
Woodville	Saucelito	12.0	0.12	0.20	0.18	1.30	0.27	1.59
Idyllwild	Saunders	12.0	0.18	0.43	0.26	2.11	0.33	2.64
Pepper	Sauterne	12.0	0.42	0.70	0.64	4.27	0.82	4.82
Milliken	Sauza	12.0	0.85	1.14	1.32	6.17	1.64	6.93
Canyon	Savi	12.0	0.52	0.77	0.63	3.50	1.76	6.29
Nelson	Savory	12.0	0.38	0.99	0.56	5.21	0.63	6.50
Inyokern	Sawmill	33.0	0.05	0.07	0.08	0.63	0.09	0.76
Arrowhead	Sawpit	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Somerset	Sawyer	12.0	1.14	1.47	1.75	8.80	2.38	10.10
Garvey	Saxon	4.16	0.06	0.09	0.08	0.82	0.11	0.96
Niguel	Saxophone	12.0	0.43	0.87	0.66	5.27	0.75	5.57
Vail	Saybrook	16.0	0.51	0.71	0.80	4.79	0.93	5.52
Gavilan (115)	Scalp	12.0	0.20	0.31	0.26	0.98	0.50	1.43
Orange	Scarlet	12.0	0.54	0.85	0.80	5.50	1.04	6.20
Columbine	Schenley	12.0	0.29	0.43	0.42	2.80	0.52	3.17
Santiago	Schilling	12.0	0.75	1.58	1.18	9.37	1.34	10.14
Maraschino	Schmidt	12.0	0.27	0.51	0.29	3.48	0.59	5.15
Santa Rosa	Scholar	12.0	0.38	0.83	0.54	3.05	0.89	4.84
Alder	Scholl	12.0	0.67	1.18	1.03	7.69	1.30	9.05
Huntington Park	School	4.16	0.13	0.19	0.20	1.15	0.23	1.22
Channel Island	Schooner	16.0	0.53	0.82	0.64	6.29	0.81	7.29
Beverly	Schuyler	4.16	0.15	0.23	0.22	1.09	0.41	1.49
Placentia	Science	12.0	0.24	0.43	0.35	2.03	0.52	2.39
Walteria	Sciurba	16.0	0.70	1.23	1.06	7.50	1.31	8.56
Hamilton	Score	12.0	0.56	1.09	0.76	6.04	1.00	7.08
Estrella	Scorpio	12.0	0.56	0.80	0.90	5.38	0.93	6.14
Scorpion P.T.	Scorpion	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Chiquita	Scotch	12.0	0.13	0.56	0.05	3.85	0.09	6.08
Visalia	Scott	4.16	0.07	0.12	0.09	0.53	0.17	0.66
Scout P.T.	Scout	12.0	0.00	0.00	0.00	0.01	0.00	0.01
Bolsa	Scow	12.0	0.33	0.64	0.46	3.99	0.55	5.02
Johanna	Scrabble	12.0	0.51	0.88	0.80	6.19	0.90	6.90
Quartz Hill	Scrapper	12.0	0.31	0.66	0.45	2.94	0.67	4.23
Stadler	Scrimmage	12.0	0.18	0.46	0.23	2.16	0.47	3.57
Tamarisk	Scruboak	12.0	0.58	1.15	0.85	5.50	1.25	8.05
El Nido	Seabass	16.0	0.82	1.24	1.32	6.96	1.41	7.07
Carpinteria	Seacliff	16.0	0.88	1.35	1.25	7.75	1.90	9.19
Hesperia	Seaforth	12.0	0.57	0.82	0.81	4.33	1.44	6.19
Milliken	Seagrams	12.0	0.45	1.30	0.72	8.19	0.76	8.73
Tahiti	Seahorse	16.0	0.07	0.13	0.10	0.76	0.11	0.78
Victorville	Seals	12.0	0.38	0.43	0.57	2.73	0.85	3.31
Hoyt	Seaman	4.16	0.11	0.16	0.15	1.15	0.20	1.32
Canyon Lake	Searay	12.0	0.31	0.59	0.38	4.47	0.65	6.67
Pico	Seaside	12.0	0.20	0.38	0.32	2.51	0.32	2.93
Stadium	Seat	12.0	0.39	0.75	0.50	3.95	0.73	4.95
Wave	Seaweed	12.0	0.39	0.85	0.50	4.69	0.67	5.72
Triton	Seawolf	12.0	0.16	0.90	0.21	3.32	0.23	5.87
Rubidoux	Sebastian	4.16	0.06	0.12	0.09	0.70	0.12	0.85
Arroyo	Seco	16.0	0.03	0.11	-0.05	1.38	-0.01	2.10
Beverly	Secretary	16.0	0.52	1.10	0.81	6.25	0.90	6.64
Santa Monica	Security	4.16	0.14	0.27	0.21	1.45	0.24	1.52
Huston	Seeley	2.4	0.06	0.11	0.10	0.64	0.11	0.76
Fairview	Segerstrom	12.0	0.35	0.87	0.53	5.15	0.60	5.58
Rosemead	Segovia	16.0	0.44	0.81	0.64	4.44	0.89	5.22
Viejo	Seguro	12.0	0.26	0.51	0.32	3.34	0.54	4.53
Etiwanda	Sellers	12.0	0.50	0.76	0.69	4.47	1.30	6.15
Victoria	Selva	16.0	1.27	1.66	1.95	10.19	2.49	11.17
Placentia	Semester	12.0	0.30	0.48	0.48	3.42	0.53	3.61
Somis	Seminary	16.0	0.23	0.32	0.24	2.57	0.39	3.42
Gavilan (115)	Seminole	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Eric	Semora	12.0	1.02	1.26	1.47	7.24	2.29	8.89
Cornuta	Senate	12.0	0.10	0.14	0.15	0.78	0.23	0.92
Cudahy	Senga	4.16	0.14	0.20	0.21	1.29	0.24	1.49
Concho	Senorita	12.0	0.55	0.67	0.80	3.62	1.33	4.68
Chatham	Sequoia	12.0	1.22	1.65	2.61	10.88	5.03	16.30
Concho	Serape	12.0	0.75	1.18	1.07	4.88	1.99	7.34
Rivera	Serapis	4.16	0.07	0.11	0.10	0.64	0.18	0.86

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Bliss	Serenity	12.0	0.55	0.94	0.86	6.30	0.95	7.84
Corona	Serfas	12.0	0.70	0.91	1.11	7.24	1.22	8.35
Pechanga	Serna	12.0	0.60	1.11	0.89	6.49	1.16	7.39
Crater	Serra	16.0	0.46	0.99	0.72	5.57	0.79	5.87
Chino	Serranos	12.0	0.94	1.18	1.40	6.55	2.12	8.40
Culver	Servo	4.16	0.13	0.16	0.17	1.18	0.27	1.41
Sespe P.T.	Sespe	4.16	0.01	0.01	0.01	0.05	0.02	0.08
Pioneer	Settler	12.0	0.64	0.77	0.96	4.43	1.42	5.18
Pedley	Sevaine	12.0	0.58	0.96	0.82	4.91	1.52	6.68
Bixby	Seventhst.	4.16	0.06	0.07	0.08	0.45	0.10	0.51
Venice Hill	Seville	12.0	0.13	0.22	0.15	0.71	0.29	1.03
Hamilton	Sewell	12.0	0.31	0.89	0.29	6.14	0.42	8.12
Saticoy	Sexton	16.0	0.38	0.40	0.23	5.17	0.47	6.82
Santa Ana River #1	Seymour	33.0	0.02	0.10	0.03	0.57	0.03	0.58
Passons	Shade	12.0	0.85	1.01	1.29	6.59	1.83	8.15
La Palma	Shadow	12.0	0.25	0.56	0.35	3.31	0.40	3.88
Chino	Shaffer	12.0	0.41	0.91	0.58	4.66	0.95	6.80
Arrowhead	Shake	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Monrovia	Shamrock	4.16	0.08	0.14	0.10	0.78	0.16	1.03
Downs	Shangrila	12.0	0.61	0.79	0.88	3.66	1.46	4.60
Gilbert	Shank	12.0	0.47	0.79	0.67	4.00	1.04	5.05
Sunnyside	Sharp	4.16	0.04	0.05	0.02	0.83	0.03	1.08
Tennessee	Shasta	12.0	0.21	0.37	0.30	2.17	0.48	2.89
Hathaway	Shaw	4.16	0.07	0.06	0.08	0.84	0.10	0.91
Cantil	Sheep	12.0	0.02	0.03	0.03	0.15	0.06	0.18
Hi Desert	Sheephole	33.0	0.01	0.01	0.01	0.06	0.01	0.07
Carpinteria	Sheffield	16.0	0.50	1.10	0.62	6.28	0.79	8.67
Bandini	Sheila	16.0	0.42	0.64	0.68	4.17	0.71	4.63
Watson	Shell	12.0	0.52	0.75	0.84	5.41	0.88	5.99
Alon	Shelldom	12.0	0.21	0.28	0.31	1.59	0.47	2.25
Potrero	Shenandoah	16.0	1.07	1.18	1.46	5.82	3.17	8.53
Moulton	Shepherd	12.0	0.40	0.82	0.46	4.51	0.95	6.89
Thornhill	Sheraton	12.0	1.23	1.52	1.81	7.00	3.09	8.90
Windsor Hills	Sherbourne	16.0	0.78	1.28	1.06	6.00	1.88	7.96
Corona	Sheridan	12.0	0.56	0.89	0.73	4.20	1.67	6.64
Fairfax	Sherman	4.16	0.10	0.10	0.15	0.77	0.17	0.81
Pepper	Sherry	12.0	0.38	0.69	0.53	3.75	0.78	4.74
Sherwood P.T.	Sherwood	4.16	0.03	0.06	0.03	0.27	0.06	0.37
Indian Wells	Sheryl	12.0	0.34	0.47	0.48	1.82	1.03	2.75
Auld	Shetland	12.0	0.10	0.29	0.11	2.23	0.11	3.01
Randall	Shine	12.0	0.30	0.61	0.38	3.44	0.71	5.16
Auld	Shipley	12.0	0.32	0.41	0.41	2.77	0.67	3.36
Lakewood	Shipway	4.16	0.05	0.09	0.03	1.02	0.06	1.41
Pepper	Shiraz	12.0	0.42	0.72	0.65	4.91	0.73	5.22
Oak Grove	Shirk	12.0	0.32	0.93	0.46	4.01	0.77	5.53
Anita	Shirley	4.16	0.06	0.07	0.09	0.62	0.14	0.75
Capitan	Shoal	16.0	0.04	0.14	0.07	0.84	0.07	0.84
Arcadia	Shoemaker	16.0	0.70	1.15	0.97	5.47	1.50	6.51
Chiquita	Shooter	12.0	0.36	0.67	0.53	4.54	0.61	4.96
Walnut	Shopper	12.0	0.23	0.26	0.32	0.90	0.58	1.37
Thousand Oaks	Shopping	16.0	1.13	1.40	1.74	7.55	2.27	8.31
Cardiff	Shops	12.0	1.03	1.36	1.60	7.54	2.04	8.29
Ramona	Shorb	4.16	0.15	0.18	0.23	1.24	0.29	1.40
Marymount	Shoreline	16.0	0.08	0.21	0.04	1.69	0.07	2.53
Junction	Shoshone	33.0	0.01	0.02	0.01	0.08	0.01	0.10
Center	Shotgun	12.0	0.64	0.80	0.97	4.53	1.37	5.25
Lawndale	Shoup	4.16	0.05	0.00	0.03	0.64	0.04	0.74
Acton	Shovel	12.0	0.25	0.51	0.32	2.26	0.56	3.63
Trophy	Show	12.0	0.75	0.88	1.14	6.54	1.45	7.84
Jersey	Showcase	16.0	0.63	0.82	0.96	4.94	1.33	5.65
Ritter Ranch	Showdown	12.0	0.24	0.47	0.34	2.24	0.51	3.16
Modena	Siam	12.0	0.23	0.44	0.22	3.03	0.53	4.69
Rialto	Sid	12.0	0.30	0.63	0.49	3.75	0.51	3.87
Estero	Sidewinder	16.0	1.22	1.56	1.86	9.84	2.45	11.02
Bryan	Sidney	12.0	0.48	0.81	0.66	5.54	0.93	6.66
Valdez	Sienna	16.0	0.63	1.04	0.84	4.34	1.87	6.68
Borrego	Siesta	12.0	0.35	0.51	0.50	4.03	0.66	4.46
Carson	Sigma	16.0	0.60	0.83	0.96	6.52	1.07	7.60
Crest	Silicone	16.0	1.76	1.78	2.48	9.57	4.62	12.11

Substation	Distribution Circuit	Voltage (kV)	Scenario 1 Coincident Capacity (MW)	Scenario 1 Total Capacity (MW)	Scenario 2 Coincident Capacity (MW)	Scenario 2 Total Capacity (MW)	Scenario 3 Coincident Capacity (MW)	Scenario 3 Total Capacity (MW)
Genamic	Silo	12.0	0.26	0.21	0.35	3.26	0.44	4.10
Randall	Silva	12.0	0.49	0.79	0.66	3.90	1.47	5.97
Limestone	Silver	12.0	0.20	0.27	0.30	2.63	0.33	2.82
Desert Outpost	Silvermoon	12.0	0.08	0.10	0.12	0.66	0.15	0.87
Cudahy	Silverside	16.0	1.11	1.66	1.67	9.65	1.98	11.18
Homart	Silvertone	12.0	0.68	1.37	1.06	7.75	1.24	8.23
Amalia	Simmons	4.16	0.14	0.23	0.20	1.28	0.28	1.44
Palmdale	Sims	12.0	0.64	0.91	0.96	5.19	1.26	6.33
Royal	Sinaloa	16.0	0.17	0.70	0.12	3.51	0.29	6.33
Santa Rosa	Sinatra	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Shawnee	Sioux	12.0	0.94	1.05	1.42	7.68	1.92	8.95
Siphon P.T.	Siphon	4.16	0.01	0.01	0.01	0.06	0.01	0.08
Firehouse	Siren	12.0	0.77	0.94	1.15	5.35	1.75	6.42
Yukon	Sitka	16.0	0.72	1.14	1.16	6.96	1.18	7.48
Skiland	Sitzmark	12.0	0.55	1.35	0.71	5.92	1.10	7.11
Santa Monica	Sixteenthst.	4.16	0.12	0.21	0.21	1.32	0.36	1.87
Narod	Sizzler	12.0	0.57	0.91	0.84	5.34	1.30	6.59
Farrell	Skelton	12.0	0.53	1.12	0.78	4.67	1.19	7.16
Casa Diablo	Ski	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Bolsa	Skiff	12.0	0.82	1.05	1.29	7.93	1.57	9.01
Terra Bella	Skinkle	12.0	0.35	0.58	0.47	2.49	0.68	3.29
Auld	Skinner	33.0	0.01	0.02	0.02	0.18	0.02	0.19
Pico	Skipper	12.0	0.01	0.02	0.01	0.11	0.02	0.15
Skyborne P.T.	Skyborne	12.0	0.05	0.10	0.07	0.49	0.12	0.70
Lucerne	Skyhi	12.0	0.44	0.54	0.65	3.48	0.84	4.63
Gisler	Skylab	12.0	1.03	1.31	1.61	7.41	1.95	8.12
Huston	Skyland	2.4	0.05	0.12	0.08	0.73	0.09	0.84
Fairview	Skypark	12.0	0.33	1.09	0.53	6.38	0.58	6.81
Kimball	Skytrain	12.0	0.30	0.48	0.48	3.66	0.48	3.94
Shuttle	Skywalker	12.0	0.43	0.73	0.53	3.50	1.25	5.95
Hoyt	Slack	4.16	0.09	0.11	0.12	0.75	0.21	0.94
Mariposa	Slade	12.0	0.02	0.03	0.03	0.15	0.05	0.18
Skiland	Slalom	12.0	0.11	0.50	0.17	2.29	0.18	3.00
Limestone	Slate	12.0	0.36	0.60	0.56	3.93	0.65	4.14
Gilbert	Slice	12.0	0.38	0.71	0.48	4.75	0.78	6.45
Chiquita	Sling	12.0	0.11	0.05	0.05	2.41	0.11	2.76
Compton	Sloan	4.16	0.10	0.15	0.14	0.87	0.17	1.00
Minaret	Slope	12.0	0.19	0.59	0.29	2.88	0.40	3.50
Bloomington	Slover	12.0	1.06	1.33	1.66	7.97	2.04	8.92
Aqueduct	Sluice	12.0	0.57	0.76	0.83	4.27	1.19	5.29
Oceanview	Smeltzer	12.0	0.97	1.03	1.40	6.49	2.20	7.85
Milliken	Smirnoff	12.0	0.87	1.23	1.38	8.01	1.54	8.60
Vail	Smith	16.0	1.09	1.44	1.73	9.15	1.94	10.77
Olympic	Smithwood	4.16	0.07	0.17	0.09	0.83	0.11	1.17
Twentynine Palms	Smoketree	12.0	0.16	0.19	0.24	1.12	0.32	1.35
Snake P.T.	Snake	4.8	0.02	0.02	0.03	0.13	0.04	0.15
Barre	Snapdragon	12.0	0.65	0.92	1.04	7.85	1.09	8.38
Lafayette	Snead	12.0	0.56	1.04	0.80	5.64	0.97	6.65
Cucamonga	Sneva	12.0	0.81	1.38	1.25	9.31	1.48	10.65
Pedley	Snipes	12.0	0.43	0.85	0.49	4.37	1.08	7.06
Big Creek 2	Snocat	12.0	0.00	0.00	0.00	0.02	0.01	0.02
Snowcreek P.T.	Snowcreek	12.0	0.01	0.01	0.01	0.05	0.01	0.07
Del Sur	Snowden	12.0	0.50	0.63	0.82	3.42	1.03	3.70
Minaret	Snowdrift	12.0	0.11	0.24	0.17	1.07	0.18	1.41
Running Springs	Snowvalley	12.0	0.14	0.23	0.19	1.34	0.26	1.64
Alessandro	Snyder	12.0	0.30	0.53	0.43	3.10	0.62	3.95
Indian Wells	Soboba	12.0	1.15	1.63	1.62	6.10	3.57	9.42
Telegraph	Socrates	12.0	0.55	0.79	0.71	4.04	1.55	6.04
Boxwood	Sodasprings	12.0	0.38	0.58	0.58	3.53	0.73	4.28
La Palma	Soho	12.0	0.05	0.06	0.08	0.44	0.09	0.46
Modoc	Sola	4.16	0.05	0.08	0.06	0.50	0.08	0.56
Maywood	Solar	4.16	0.11	0.16	0.16	1.03	0.18	1.16
Bunker	Soldier	12.0	0.41	0.77	0.60	4.40	0.79	5.23
Repetto	Soledad	16.0	0.66	1.39	1.01	8.05	1.21	8.93
Johanna	Solitaire	12.0	0.34	0.74	0.55	5.01	0.56	5.70
Concho	Sombrero	12.0	0.98	1.50	1.52	8.08	1.78	9.43
Team	Sonics	12.0	0.76	0.95	1.06	6.09	1.48	7.47
Valley	Sonoma	12.0	0.25	0.63	0.35	3.36	0.44	4.63
Sonrisa P.T.	Sonrisa	2.4	0.02	0.03	0.02	0.21	0.03	0.26

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Soper P. T.	Soper	4.16	0.12	0.14	0.16	0.93	0.32	1.18
Stetson	Sopwith	12.0	0.18	0.29	0.27	1.64	0.38	1.88
Valdez	Sorrento	16.0	0.84	1.04	1.30	5.85	1.67	6.36
Manhattan	Sostrand	4.16	0.05	0.11	0.08	0.83	0.10	1.06
Hathaway	Soto	12.0	0.64	1.32	0.98	8.40	1.08	9.01
Southridge P.T.	Southridge	4.16	0.07	0.10	0.10	0.49	0.16	0.63
Thornhill	Spa	12.0	1.04	1.31	1.64	7.63	1.79	8.13
Johanna	Spades	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Ganesha	Spadra	12.0	1.02	1.23	1.54	6.87	2.09	7.83
Citrus	Spanada	12.0	0.85	0.99	1.08	4.76	2.94	7.87
Highland	Sparks	12.0	0.75	0.94	1.14	6.08	1.72	7.81
Tennessee	Sparling	12.0	0.27	0.71	0.34	3.06	0.72	5.11
Talbert	Sparrow	12.0	0.81	1.04	1.30	8.35	1.41	8.96
Carson	Sparton	16.0	1.03	1.32	1.61	9.28	2.00	10.94
Linden	Spaulding	4.16	0.12	0.22	0.18	1.27	0.21	1.41
Hamilton	Speaker	12.0	0.01	0.03	0.02	0.16	0.02	0.17
Apple Valley	Spear	12.0	0.49	0.80	0.71	3.70	1.04	4.93
Chino	Spectrum	12.0	0.89	1.09	1.32	6.48	2.05	8.23
Declez	Speedway	12.0	4.16	8.32	6.72	75.02	6.84	81.66
Friendly Hills	Spencer	4.16	0.10	0.17	0.14	0.81	0.30	1.18
Hinkley	Speth	12.0	0.18	0.27	0.31	1.41	0.49	1.78
San Bernardino	Sphinx	12.0	0.36	0.59	0.52	3.04	0.75	3.47
Moreno	Spice	12.0	0.36	0.59	0.47	2.73	1.12	4.42
Bloomington	Spike	12.0	0.87	1.03	1.24	4.94	2.37	6.56
Rio Hondo	Spillway	16.0	0.49	0.69	0.74	4.76	0.92	5.14
Topaz	Spinel	4.16	-0.03	0.00	-0.10	0.19	-0.09	0.56
Duarte	Spinks	4.16	0.07	0.12	0.08	0.62	0.16	0.95
Channel Island	Spinnaker	16.0	0.64	1.29	0.93	8.41	1.06	8.95
Lennox	Spinning	4.16	0.10	0.19	0.15	1.17	0.16	1.41
Stetson	Spitfire	12.0	0.44	0.88	0.66	4.63	0.88	5.26
Newbury	Splendor	16.0	0.38	0.56	0.50	2.47	0.74	3.14
Carmenita	Splendora	12.0	0.61	0.77	0.93	5.94	1.07	6.66
Minaret	Sportsman	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Mayberry	Sprague	12.0	0.36	0.68	0.51	3.86	0.78	5.12
Seabright	Spray	12.0	0.19	0.39	0.30	2.21	0.34	2.40
Signal Hill	Spring	12.0	0.84	1.24	1.35	7.13	1.45	7.26
Savage	Springvalley	12.0	0.25	0.30	0.48	2.69	0.71	4.05
Trophy	Sprint	12.0	0.87	1.06	1.27	5.74	2.17	7.28
Navy Mole	Spruance	12.0	0.13	0.31	0.21	1.78	0.21	1.78
Montebello	Spruce	4.16	0.14	0.23	0.20	1.25	0.25	1.46
Palmdale	Spur	12.0	0.59	0.79	0.78	3.85	1.36	5.34
Hanford	Squadron	12.0	0.79	1.29	1.12	5.21	1.96	7.60
Neptune	Squall	12.0	0.38	0.28	0.53	2.59	0.91	3.10
Arrowhead	Squint	12.0	0.12	0.32	0.19	1.73	0.20	2.13
Bedford	Squires	4.16	0.10	0.19	0.14	0.90	0.21	1.06
Modena	Srilanka	12.0	0.33	0.51	0.50	3.84	0.68	5.74
Alhambra	St.Charles	16.0	0.15	0.22	0.22	1.47	0.27	1.74
Bryan	St.Croix	12.0	0.84	1.39	1.34	10.03	1.45	10.59
Venice Hill	St.Johns	12.0	0.40	0.70	0.53	4.51	0.77	5.67
Bryan	St.Thomas	12.0	0.25	0.38	0.50	3.24	0.87	5.01
Palm Canyon	Stack	12.0	0.62	0.75	0.90	3.25	1.60	4.16
Felton	Stacy	4.16	0.02	-0.04	-0.01	0.55	-0.01	0.70
Puente	Stafford	12.0	0.61	0.98	0.84	4.63	1.38	6.66
Carmenita	Stage	12.0	0.49	0.76	0.78	6.50	0.88	7.64
Ivyglen	Stageline	12.0	0.26	0.57	0.35	3.05	0.65	4.80
Bain	Staghorn	12.0	0.36	0.60	0.52	3.18	0.87	4.27
Peyton	Stalling	12.0	0.63	0.60	0.75	3.30	2.29	5.99
Gallatin	Stamper	12.0	1.05	1.33	1.66	8.43	1.86	8.89
Oceanview	Standard	12.0	0.76	1.36	1.06	8.17	1.28	9.56
Rancho	Standingrock	12.0	0.55	0.68	0.96	5.50	1.28	7.68
Mayflower	Standish	4.16	0.11	0.11	0.13	0.79	0.29	1.19
Mayberry	Stanford	12.0	0.26	0.69	0.37	3.94	0.44	5.42
Santa Barbara	Stanwood	16.0	0.35	0.87	0.41	5.35	0.54	6.68
Neptune	Starboard	12.0	0.59	0.72	0.89	3.99	1.24	4.51
Santa Fe Springs	Starbuck	12.0	1.21	1.67	3.10	9.33	6.90	14.97
Lockheed	Starfighter	16.0	0.51	1.03	0.65	5.71	1.13	7.97
Estrella	Stargazer	12.0	1.19	1.72	1.92	11.51	2.00	13.15
Cajalco	Starglow	12.0	0.49	1.03	0.74	6.78	1.00	9.49
Canyon	Starrock	12.0	0.47	0.72	0.77	4.66	1.19	6.28

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Walteria	Statler	16.0	0.40	0.78	0.46	4.03	1.00	6.37
Oasis	Stealth	12.0	0.62	1.17	0.85	6.05	1.10	8.15
Seabright	Steam	12.0	0.12	0.24	0.19	1.47	0.20	1.56
Santa Susana	Stearns	16.0	0.67	1.01	0.87	5.71	1.51	8.09
Ridgeview P.T.	Steel	12.0	0.04	0.05	0.05	0.32	0.07	0.34
Liberty	Steelman	12.0	0.56	1.12	0.83	5.51	1.03	7.47
Del Rosa	Stegman	12.0	0.46	0.92	0.71	5.01	0.83	5.28
Marion	Stella	12.0	0.23	0.67	0.23	4.44	0.31	6.12
Tippecanoe	Sterling	4.16	0.07	0.14	0.11	0.80	0.14	0.96
Clark	Stevely	4.16	0.14	0.26	0.15	1.40	0.25	2.00
Culver	Stevens	4.16	-0.04	-0.11	-0.18	0.48	-0.15	0.84
Big Creek 2	Stevenson	12.0	0.01	0.02	0.01	0.03	0.02	0.06
Beaumont	Stewart	4.16	0.09	0.19	0.13	1.02	0.16	1.24
Stewval P.T.	Stewval	25.0	0.00	0.00	0.00	0.00	0.00	0.00
Cucamonga	Stig	12.0	0.43	0.56	0.68	3.66	0.74	4.19
Dryden P.T.	Stillwater	12.0	0.00	0.00	-0.01	-0.05	-0.01	-0.04
MacArthur	Stillwell	12.0	0.59	1.34	0.94	7.94	1.01	8.20
Palmdale	Sting	12.0	0.39	0.44	0.57	3.61	0.70	4.06
Chiquita	Stinger	12.0	0.16	0.29	0.16	2.52	0.25	3.20
Lighthipe	Stitzer	12.0	1.17	1.44	1.75	7.69	2.67	8.83
Gallatin	Stoakes	12.0	0.04	0.06	0.06	0.30	0.10	0.38
Alon	Stocco	12.0	1.26	1.51	2.00	13.55	2.26	16.70
Bloomington	Stockcar	12.0	0.41	0.82	0.59	4.52	0.87	5.92
Windsor Hills	Stocker	16.0	0.30	0.59	0.36	3.25	0.50	4.24
Hanford	Stockton	12.0	0.34	0.43	0.49	1.99	0.84	2.54
Compton	Stockwell	4.16	0.18	0.27	0.26	1.81	0.29	1.99
Milliken	Stoli	12.0	0.90	1.17	1.41	7.21	1.77	8.03
Columbine	Stone	12.0	0.09	0.13	0.12	0.64	0.18	0.78
Ravendale	Stoneley	16.0	0.58	1.12	0.77	5.93	1.22	7.69
Skylark	Stoneman	12.0	0.26	0.55	0.36	2.78	0.60	4.01
Yucaipa	Stonewood	12.0	0.30	0.50	0.44	3.46	0.55	4.11
Etiwanda	Stooges	12.0	1.66	2.30	4.45	12.60	9.67	20.75
Chino	Storage	12.0	0.59	0.71	0.81	3.79	1.77	5.65
Outlet P.T.	Stores	12.0	0.80	0.93	1.11	3.30	2.23	4.67
Vegas	Storke	16.0	0.65	1.22	0.81	8.71	1.05	9.96
Neptune	Storm	12.0	0.84	0.94	1.25	5.78	1.84	6.60
Granada	Story	4.16	0.06	0.09	0.08	0.64	0.10	0.70
Chiquita	Stout	12.0	0.16	0.33	0.16	2.82	0.21	3.76
Moorpark	Strathern	16.0	1.08	1.17	1.55	7.84	2.27	9.53
Perry	Strawberry	4.16	0.04	0.06	0.07	0.47	0.07	0.55
Bloomington	Streamliner	12.0	0.72	0.91	1.06	4.54	1.71	5.66
Huntington Park	Streetlight	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Bridge	Stringer	4.16	0.10	0.15	0.12	1.17	0.15	1.46
Auld	Striper	33.0	0.13	0.47	0.21	2.87	0.21	3.08
Stroh P.T.	Stroh	4.16	0.03	0.04	0.04	0.23	0.09	0.31
Bridgeport	Strosnider	16.0	0.11	0.23	0.15	1.01	0.22	1.24
Banning	Stubby	33.0	0.02	0.03	0.04	0.25	0.04	0.25
Carmenita	Studebaker	12.0	0.72	0.97	1.07	5.76	1.56	7.04
Placentia	Student	12.0	0.55	1.03	0.69	5.90	1.00	7.27
Bliss	Sturgeon	12.0	0.53	0.65	0.80	4.64	1.12	5.97
Narrows	Stutz	12.0	0.18	0.55	0.18	3.29	0.23	4.79
Anaverde	Subida	12.0	1.09	1.46	1.65	7.41	2.28	8.57
Railroad	Subway	12.0	0.22	0.60	0.34	3.18	0.41	4.32
Porterville	Success	12.0	0.63	1.20	0.92	5.56	1.13	7.42
Modena	Sudan	12.0	0.18	0.46	0.15	2.43	0.30	3.73
Sullivan	Sugar	12.0	1.03	1.27	1.56	6.86	2.02	7.68
Sugarloaf P.T.	Sugarloaf	2.4	0.00	0.00	0.00	0.03	0.00	0.04
Sullivan	Sully	12.0	0.56	0.81	0.88	4.65	1.06	4.92
Tamarisk	Sumac	12.0	0.87	1.05	1.28	5.01	2.17	6.41
Windsor Hills	Summerhill	16.0	0.63	1.21	0.95	6.84	1.19	7.32
Haveda	Sump	4.16	0.02	0.02	0.02	0.23	0.02	0.28
Stoddard	Sun	4.16	0.00	0.00	0.00	0.01	0.01	0.01
Felton	Sundale	4.16	0.08	0.13	0.12	0.82	0.15	0.94
Sun City	Sundance	12.0	0.23	0.77	0.30	3.72	0.39	5.43
Helendale	Sundown	12.0	0.79	1.39	1.19	7.07	1.65	9.74
Hi Desert	Sunfair	25.0	0.07	0.22	0.11	1.01	0.11	1.37
Fairview	Sunflower	12.0	0.55	1.21	0.83	6.67	1.04	7.35
Sun City	Sunglasses	12.0	0.24	0.61	0.33	3.67	0.38	4.52
Rivera	Sunglow	4.16	0.17	0.19	0.23	1.18	0.48	1.53

Substation	Distribution Circuit	Voltage (kV)	Scenario 1 Coincident Capacity (MW)	Scenario 1 Total Capacity (MW)	Scenario 2 Coincident Capacity (MW)	Scenario 2 Total Capacity (MW)	Scenario 3 Coincident Capacity (MW)	Scenario 3 Total Capacity (MW)
Citrus	Sunkist	12.0	0.36	0.50	0.52	2.68	0.72	3.30
Sunlight P.T.	Sunlight	4.16	0.03	0.07	0.05	0.41	0.06	0.50
Cathedral City	Sunnylane	4.8	0.00	0.01	0.01	0.02	0.01	0.03
San Gabriel	Sunnyslope	4.16	0.11	0.17	0.14	1.00	0.23	1.27
Carodean	Sunnyvale	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Victor	Sunnyvista	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Poplar	Sunset	12.0	0.42	0.56	1.16	3.70	2.48	5.20
San Antonio	Sunsweet	12.0	0.87	1.08	1.33	5.87	1.77	6.46
Belding	Suntan	4.16	0.14	0.22	0.20	0.95	0.36	1.37
Santa Monica	Suntower	16.0	0.96	2.03	1.50	11.18	1.69	11.50
Little Rock	Sunvillage	12.0	0.46	0.57	0.92	4.00	1.68	5.27
Watson	Superior	12.0	1.08	1.33	1.65	8.36	2.20	9.86
Ganesha	Supreme	12.0	0.55	0.65	0.76	3.79	1.31	5.00
Santa Monica	Surfrider	16.0	0.21	0.44	0.32	2.35	0.38	2.46
Channel Island	Surfside	16.0	0.81	1.33	1.17	8.02	1.41	8.89
Timoteo	Surgeon	12.0	0.33	0.71	0.45	3.63	0.61	4.65
Tipton	Surprise	12.0	0.63	0.90	0.93	6.80	1.39	9.83
Surrey U.G.S.	Surrey	4.16	0.04	0.08	0.04	0.29	0.10	0.57
Gisler	Surveyor	12.0	0.41	0.55	0.65	4.26	0.73	4.72
Alder	Susan	12.0	0.72	1.18	1.07	7.64	1.52	9.56
Riverway	Susquehanna	12.0	0.45	0.69	0.66	3.60	0.87	4.53
Lawndale	Sutro	4.16	0.05	0.07	0.07	0.54	0.08	0.58
Del Rosa	Sutt	12.0	0.46	0.75	0.65	3.70	1.17	4.84
Puente	Suzy	12.0	0.38	0.96	0.57	4.97	0.68	7.04
Tulare	Swall	12.0	0.51	1.28	0.69	5.96	1.14	7.91
Delano	Swanson	12.0	0.92	1.22	1.41	7.40	1.74	8.77
Hanford	Swatzke	12.0	0.40	0.96	0.55	3.75	1.01	6.15
Shandin	Sweetwater	12.0	0.25	0.71	0.34	3.73	0.43	5.27
Fairfax	Sweetzer	4.16	0.08	0.13	0.12	0.72	0.13	0.82
Montecito	Swift	4.16	0.14	0.26	0.19	1.24	0.33	1.70
Dryden P.T.	Swiftwater	12.0	0.45	0.91	0.60	3.34	1.29	4.89
Archibald	Swiss	12.0	0.04	0.33	-0.18	3.34	-0.07	6.00
Visalia	Swoose	12.0	0.85	1.09	1.27	5.06	1.79	5.94
Redlands	Sylvan	4.16	0.04	0.08	0.06	0.50	0.09	0.69
Deep Springs	Sylvania	2.4	0.01	0.02	0.01	0.08	0.01	0.09
Topanga	Sylvia	4.16	0.07	0.10	0.08	0.50	0.20	0.84
Rancho	Symeron	12.0	0.83	1.01	1.18	4.65	2.21	6.71
Concho	Taberna	12.0	1.00	1.33	1.47	6.41	2.16	8.04
Holiday	Tachevah	4.16	0.06	0.09	0.10	0.39	0.14	0.48
Stadler	Tackle	12.0	0.71	1.31	1.08	8.27	1.39	9.51
Fairview	Tacoma	12.0	0.43	0.93	0.69	5.58	0.75	6.00
Colorado	Taft	16.0	0.58	1.27	0.91	7.26	1.03	7.64
Running Springs	Taggert	12.0	0.04	0.07	0.05	0.36	0.07	0.42
Goshen	Tagus	12.0	0.37	0.47	0.54	3.07	0.90	4.25
Tahquitz P.T.	Tahquitz	12.0	0.02	0.06	0.03	0.25	0.04	0.34
Modena	Taiwan	12.0	0.39	1.01	0.52	5.79	0.65	7.39
Alhambra	Takning	16.0	0.69	1.20	0.97	6.56	1.37	7.73
Indian Wells	Takota	12.0	0.40	0.49	0.56	2.02	1.03	2.75
Dunn Siding	Talc	12.0	0.02	0.03	0.03	0.12	0.04	0.13
Perry	Talent	4.16	0.05	0.06	0.06	0.58	0.08	0.64
Thousand Oaks	Talley	16.0	0.99	1.27	1.32	8.06	2.01	10.35
Savage	Talpa	12.0	0.52	0.70	0.73	3.19	1.18	4.18
Tortilla	Tamale	12.0	0.39	0.87	0.59	4.70	0.69	5.16
Alder	Tamarind	12.0	0.42	0.74	0.61	4.22	0.90	5.33
Elizabeth Lake	Tambourine	16.0	0.56	0.84	0.79	5.49	1.25	6.85
Bandini	Tammy	16.0	0.25	0.32	0.38	1.95	0.54	2.26
Rush	Tamora	16.0	0.47	0.70	0.66	3.87	0.99	4.82
Cardiff	Tampico	12.0	0.65	0.84	1.02	4.91	1.26	5.35
Ravendale	Tamworth	4.16	-0.02	0.00	-0.08	0.39	-0.06	0.79
Orange	Tan	12.0	0.32	0.51	0.47	3.18	0.61	3.54
Walteria	Tandem	16.0	0.42	0.68	0.62	4.69	0.79	5.40
Citrus	Tangerine	12.0	0.50	0.61	0.71	3.09	1.30	4.09
Santa Rosa	Tanglewood	12.0	0.77	1.14	1.14	5.00	1.84	6.69
Allen	Tanoble	4.16	0.23	0.22	0.27	1.14	0.85	2.09
Fremont	Taper	4.16	0.12	0.18	0.17	1.27	0.19	1.46
Tapia	Tapia#1	16.0	0.00	0.00	0.00	0.00	0.00	0.00
Santa Susana	Tapo	16.0	0.41	0.87	0.54	4.03	0.72	5.37
Lancaster	Target	12.0	0.96	1.27	1.50	6.89	1.77	7.46
Bayside	Tarpon	12.0	0.70	1.55	1.03	8.60	1.21	9.46

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Beverly	Tartar	16.0	0.80	1.53	1.20	8.25	1.49	8.91
Venice Hill	Tarusa	12.0	0.25	0.45	0.28	1.52	0.53	2.26
Tatanka P.T.	Tatanka	4.16	0.06	0.20	0.08	0.93	0.08	1.44
Center	Tattoo	12.0	0.47	0.54	0.68	2.82	1.16	3.51
Estrella	Taurus	12.0	0.47	0.83	0.74	6.37	0.82	7.47
Cajalco	Tava	12.0	0.27	0.69	0.36	3.08	0.71	5.01
Visalia	Taylor	12.0	0.54	0.88	0.78	4.91	1.42	6.05
Placentia	Teacher	12.0	0.61	0.94	0.91	5.91	1.17	6.48
Torrance	Teak	16.0	0.90	1.27	1.38	6.53	1.87	7.55
Porterville	Teapot	12.0	0.61	0.94	0.90	4.89	1.34	6.32
Vegas	Tecolote	16.0	0.04	0.22	-0.17	3.09	-0.06	4.43
Gilbert	Tee	12.0	0.07	-0.03	0.03	1.53	0.06	1.78
Havilah	Teevee	12.0	0.02	0.03	0.04	0.19	0.05	0.20
Neenach	Tejon	12.0	0.17	0.31	0.24	1.52	0.31	1.98
Tejon Peak P.T.	Tejonpeak	2.4	0.01	0.01	0.01	0.05	0.01	0.05
Francis	Telephone	12.0	0.41	0.68	0.57	3.18	1.14	4.55
Cabrillo	Teller	12.0	0.08	0.15	-0.10	2.95	0.01	4.04
Pierpont	Teloma	4.16	0.04	-0.01	0.03	0.37	0.07	0.52
Rosemead	Telstar	16.0	0.58	1.08	0.77	6.28	1.06	7.57
Moraga	Temeck	12.0	0.17	0.67	0.20	3.14	0.30	5.11
Belmont	Temple	4.16	0.16	0.26	0.24	1.57	0.28	1.73
Bloomington	Tender	12.0	0.47	0.57	0.65	2.92	1.34	4.10
Tenderfoot P.T.	Tenderfoot	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Frazier Park	Tenneco	12.0	0.50	1.10	0.72	6.05	0.87	7.31
Perry	Tenor	4.16	0.05	-0.01	0.02	0.75	0.05	0.97
Woodruff	Tenpin	4.16	0.07	0.10	0.14	0.80	0.21	0.97
Placentia	Term	12.0	0.22	0.34	0.29	3.19	0.34	3.44
Dike	Terminal	12.0	0.00	0.01	0.01	0.06	0.01	0.09
Lemon Cove	Terminus	12.0	0.22	0.26	0.30	0.88	0.67	1.31
Archline	Terra	12.0	0.38	0.70	0.59	4.56	0.67	5.03
Elsinore	Terracotta	33.0	0.14	0.22	0.22	2.44	0.23	3.23
Passons	Terradell	12.0	0.82	0.99	1.20	5.92	1.67	7.33
Palos Verdes	Terrazzo	4.16	0.01	0.05	-0.04	0.75	-0.03	1.07
Moulton	Terrier	12.0	0.35	0.98	0.40	5.13	0.61	7.40
Stadium	Terry	12.0	0.17	0.05	0.07	4.41	0.10	4.87
Corona	Tesoro	12.0	0.40	0.61	0.54	3.38	1.06	4.78
Alhambra	Test	16.0	0.49	0.89	0.54	4.58	0.96	6.29
Viejo	Testarudo	12.0	0.11	0.16	0.08	1.34	0.26	2.23
Huston	Tetley	12.0	0.13	0.28	0.18	1.51	0.23	1.79
Johanna	Tetris	12.0	0.34	0.53	0.49	3.91	0.64	4.59
Stadium	Tevis	12.0	1.56	2.88	5.21	14.61	13.28	27.77
Center	Texas	12.0	0.90	1.18	1.44	7.29	1.61	7.83
Glen Avon	Texfi	12.0	0.41	0.74	0.60	3.73	0.90	4.51
Ojai	Thacher	16.0	1.25	2.07	1.38	7.60	2.55	11.54
Rio Hondo	Thames	12.0	0.73	0.93	1.07	4.51	1.56	5.35
Laguna Bell	Theater	16.0	1.03	1.30	1.58	7.52	2.11	8.12
La Veta	Thelma	12.0	0.40	0.66	0.57	3.77	0.78	4.35
Bandini	Thermador	16.0	0.45	0.63	0.72	4.14	0.80	4.59
Pomona	Thomas	4.16	0.16	0.18	0.24	1.11	0.32	1.27
Highland	Thompsen	12.0	0.85	1.65	1.27	9.12	1.63	10.55
Francis	Thor	12.0	0.78	0.94	1.21	6.60	1.36	7.09
Palmdale	Thornburg	12.0	0.51	0.66	0.75	3.75	1.11	4.64
Mayberry	Thornton	12.0	0.22	0.58	0.32	3.13	0.38	4.26
Auld	Thoroughbred	12.0	0.16	0.57	0.13	3.74	0.21	5.84
Cypress	Thorpe	12.0	1.02	1.11	1.55	8.88	2.13	10.71
Triton	Thresher	12.0	0.38	0.91	0.54	4.28	0.89	6.25
Wrightwood	Thrush	2.4	0.03	0.09	0.05	0.54	0.05	0.66
Oasis	Thunderbolt	12.0	0.47	0.63	0.70	3.58	1.01	4.33
Fremont	Tichenor	16.0	0.85	1.15	1.28	6.82	1.83	8.23
Stadium	Ticket	12.0	0.63	1.11	0.87	6.83	1.19	8.14
Casitas	Tico	16.0	0.31	0.27	0.34	3.41	0.48	3.92
Lucas	Tide	4.16	0.07	0.06	0.09	0.67	0.12	0.74
Cortez	Tienda	12.0	0.83	1.07	1.26	5.66	1.65	6.46
Little Rock	Tierrabonita	12.0	0.03	0.03	0.04	0.24	0.06	0.25
Center	Tiger	12.0	0.87	1.09	1.35	6.34	1.73	7.06
Kimball	Tigercat	12.0	0.00	0.00	0.00	0.00	0.00	0.00
Rio Hondo	Tigris	12.0	0.83	1.01	1.31	7.84	1.51	8.25
Wimbledon	Tilden	12.0	0.67	1.04	1.04	6.66	1.25	7.58
Narod	Tile	12.0	0.63	1.01	0.88	5.29	1.40	6.59

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Fillmore	Timbercanyon	16.0	0.34	0.47	0.55	3.26	0.77	3.73
Lucerne	Timco	12.0	0.20	0.31	0.29	1.59	0.41	2.07
Sierra Madre	Times	4.16	0.02	0.13	0.02	0.52	0.02	0.91
Niguel	Timpani	12.0	0.17	0.65	0.12	3.97	0.16	6.17
Limestone	Tin	12.0	0.21	0.32	0.25	3.42	0.29	3.71
Hamilton	Tinker	12.0	0.17	0.47	0.16	3.24	0.22	4.33
El Sobrante	Tinmine	12.0	0.02	0.03	0.03	0.18	0.05	0.22
Murphy	Tipperary	12.0	0.26	0.59	0.36	3.36	0.44	3.84
Saugus	Tips	16.0	0.57	0.71	0.90	4.74	1.07	5.25
Estero	Tiros	16.0	0.95	1.17	1.44	7.08	2.12	8.42
Little Rock	Titan	12.0	0.45	0.76	0.63	3.44	0.93	4.62
Camden	Titanium	12.0	0.63	1.04	0.96	6.85	1.17	7.63
Brookhurst	Tittle	12.0	0.89	0.98	1.15	6.82	1.76	8.59
Peyton	Titus	12.0	0.48	1.12	0.67	7.85	0.76	9.73
Mt. Wilson	Tivo	16.0	0.85	1.01	1.39	5.85	1.41	5.88
Los Cerritos	Tizzard	12.0	0.04	0.10	0.06	0.58	0.06	0.59
Liberty	Tlsmith	12.0	0.34	0.58	0.46	2.66	0.89	3.47
Del Amo	Toblerone	12.0	0.26	0.37	0.41	2.27	0.52	2.39
Haskell	Toga	16.0	0.29	0.28	0.35	3.77	0.45	4.15
Declez	Tokay	12.0	0.67	0.86	0.98	4.78	1.57	6.11
Arroyo	Tola	16.0	0.20	0.28	0.22	2.62	0.32	2.93
Santiago	Tolar	12.0	0.43	0.91	0.69	5.47	0.73	5.88
Naples	Toledo	4.16	0.08	0.34	0.10	1.93	0.16	2.38
Whitewater	Toll	4.16	0.03	0.06	0.03	0.30	0.05	0.34
Tollhouse P.T.	Tollhouse	4.16	0.01	0.01	0.01	0.05	0.02	0.06
Indian Wells	Toltec	12.0	0.90	1.06	1.33	4.79	2.11	5.73
Chase	Tolton	12.0	0.58	1.01	0.85	5.74	1.14	6.65
Monolith	Tomahawk	12.0	1.08	1.34	1.54	6.14	2.43	7.53
Oasis	Tomcat	12.0	0.36	0.71	0.56	4.22	0.59	5.27
Merced	Tommy	12.0	0.74	0.98	1.00	4.90	2.21	7.00
Palm Village	Ton	12.0	0.69	0.78	1.08	4.72	1.20	4.90
Milliken	Tonic	12.0	0.68	1.24	1.08	7.37	1.14	8.02
La Habra	Tonner	12.0	0.27	0.61	0.32	3.40	0.46	4.29
Apple Valley	Tonto	12.0	0.62	0.86	0.89	4.38	1.50	5.84
Industry	Tool	12.0	0.72	0.88	1.16	6.78	1.28	7.23
Rivera	Topeka	4.16	0.25	0.39	0.38	2.24	0.59	2.61
Landing	Topoc	16.0	0.23	0.42	0.36	2.05	0.40	2.51
Bassett	Torchlight	12.0	0.63	0.72	0.93	4.33	1.43	5.21
Las Lomas	Torino	12.0	0.25	0.70	0.30	4.41	0.34	5.47
Yorba Linda	Tornado	12.0	0.40	0.99	0.52	3.97	1.08	6.55
Canadian P.T.	Toronto	12.0	0.10	0.25	0.14	1.18	0.17	1.51
Narrows	Torpedo	12.0	0.38	0.61	0.58	4.65	0.64	5.09
Yorba Linda	Torrent	12.0	0.15	0.73	0.13	3.28	0.15	5.77
Santa Rosa	Torropeak	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Carson	Torson	16.0	2.17	3.22	5.41	18.86	11.20	30.00
Farrell	Tortuga	12.0	0.57	1.12	0.88	5.80	0.99	7.39
Washington	Touchdown	12.0	0.71	0.88	1.07	4.81	1.38	5.39
Topaz	Tourmaline	4.16	0.06	0.09	0.06	0.88	0.11	1.36
Gilbert	Tourney	12.0	0.82	1.40	2.31	8.60	5.62	14.95
Ganesha	Tower	4.16	0.11	0.13	0.16	1.04	0.27	1.26
Garnet	Townhall	33.0	0.01	0.01	0.01	0.05	0.01	0.06
Potrero	Townsgate	16.0	0.45	0.57	0.54	3.35	1.36	5.34
Santa Susana	Township	16.0	0.68	1.25	0.94	6.25	1.24	8.09
Lindsay	Towt	4.16	0.18	0.21	0.26	0.89	0.44	1.20
Cherry	Toyon	12.0	0.08	0.14	0.11	0.77	0.15	0.93
Irvine	Trabuco	12.0	0.13	0.10	0.05	2.29	0.25	3.43
Michillinda	Track	4.16	0.04	0.12	0.05	0.70	0.05	1.00
Declez	Tractor	12.0	0.59	0.67	0.93	5.28	1.18	5.98
Santa Monica	Tradewind	16.0	0.93	2.10	1.31	12.33	1.55	13.67
Line Creek	Trail	4.16	0.00	0.01	0.01	0.03	0.01	0.03
Mascot	Trailblazer	12.0	0.38	0.85	0.49	3.37	0.93	5.01
Railroad	Train	12.0	0.48	0.44	0.55	3.15	1.26	5.32
Garnet	Tram	33.0	0.00	0.01	0.01	0.08	0.01	0.09
Cathedral City	Tramview	4.8	0.12	0.16	0.18	0.83	0.25	0.97
Fruitland	Transit	16.0	0.66	0.85	1.02	4.54	1.38	5.15
Ditmar	Transplant	4.16	0.07	0.06	0.04	1.16	0.05	1.49
Alder	Trapp	12.0	0.50	0.93	0.73	5.20	0.99	6.38
Pioneer	Trapper	12.0	1.28	1.60	2.00	10.96	2.34	12.40
Cajalco	Trautwein	12.0	0.51	1.25	0.66	5.93	1.26	9.40

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Santa Rosa	Travis	12.0	0.65	0.84	0.95	3.88	1.65	5.03
Montecito	Tremaine	4.16	0.21	0.38	0.28	1.66	0.57	2.53
Bedford	Trenton	4.16	0.09	0.29	0.13	1.47	0.14	1.97
Railroad	Trestle	12.0	0.51	0.37	0.62	2.91	1.53	4.95
Eisenhower	Trevino	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Gallatin	Trey	12.0	0.63	0.95	0.88	5.34	1.51	6.82
Beverly	Triangle	4.16	0.13	0.18	0.20	0.94	0.24	0.99
Indian Wells	Tribal	12.0	0.58	1.10	0.85	4.78	1.22	6.70
State Street	Tribune	12.0	0.05	0.08	0.07	0.44	0.10	0.49
Alhambra	Tricity	16.0	0.47	0.88	0.73	5.69	0.88	6.98
Nogales	Trident	12.0	0.35	0.87	0.49	5.03	0.60	5.99
Isla Vista	Trigo	16.0	0.94	1.45	1.45	10.56	1.65	10.92
Broadway	Trimble	4.16	0.10	0.13	0.10	1.36	0.13	1.77
Ely	Trinidad	12.0	0.62	0.68	0.81	4.58	1.70	6.46
Alessandro	Trinity	12.0	0.26	0.54	0.38	2.90	0.58	3.97
Borrego	Tripas	12.0	0.35	0.38	0.41	3.00	0.98	4.46
Alhambra	Triumph	16.0	0.00	0.00	0.00	0.00	0.00	0.00
Malibu	Triunfo	16.0	0.55	0.67	0.80	2.96	1.36	3.78
Bullis	Trochu	16.0	0.75	1.01	1.13	5.85	1.62	6.77
Niguel	Trombone	12.0	0.09	0.40	0.04	2.03	0.10	3.42
Lancaster	Tropico	12.0	0.88	1.33	1.34	7.07	1.60	8.03
Ravendale	Trotter	16.0	0.09	0.16	0.10	0.73	0.18	1.00
Doheny	Trousdale	4.16	0.11	0.21	0.16	1.07	0.23	1.28
Casa Diablo	Trout	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Hoyt	Troy	4.16	0.12	0.18	0.17	0.99	0.25	1.15
Floraday	Trublu	4.16	0.04	0.21	0.05	0.91	0.07	1.56
Firehouse	Truck	12.0	0.43	0.73	0.63	4.10	0.95	5.24
Stirrup	Trudie	4.16	0.01	0.08	-0.01	0.55	-0.01	0.96
Valley	Trumble	12.0	0.12	0.23	0.15	1.57	0.26	2.22
Goleta	Trump	16.0	0.07	0.12	0.08	0.53	0.15	0.71
Elizabeth Lake	Trumpet	16.0	0.23	1.01	0.14	5.00	0.26	8.23
Bridge	Truss	4.16	0.11	0.11	0.11	1.32	0.15	1.57
Yorba Linda	Tsunami	12.0	0.22	0.91	0.23	3.42	0.40	6.01
Elizabeth Lake	Tuba	16.0	0.26	0.51	0.34	2.52	0.58	3.48
Vail	Tube	16.0	1.31	1.85	2.09	12.27	2.34	14.05
Bullis	Tucker	4.16	0.09	0.15	0.14	0.95	0.16	1.09
Mayberry	Tudor	12.0	0.54	0.92	0.71	3.59	1.48	5.72
Lundy	Tufa	16.0	0.01	0.04	0.02	0.18	0.02	0.21
Tulare	Tuggle	12.0	0.55	0.90	0.75	3.81	1.44	5.02
Placentia	Tuition	12.0	0.43	0.84	0.58	4.18	0.81	4.89
Lucas	Tulane	4.16	0.28	0.30	0.37	1.24	0.87	1.86
Barre	Tulip	12.0	0.33	0.73	0.47	4.86	0.53	5.85
Padua	Tully	12.0	0.54	0.90	0.70	3.88	1.75	6.53
Trask	Tulsa	12.0	0.73	0.97	1.06	5.17	1.43	6.10
Tumbleweed P.T.	Tumbleweed	2.4	0.01	0.02	0.02	0.09	0.02	0.10
Tapia	Tuna	16.0	0.46	0.58	0.51	6.35	0.66	6.71
Greening	Tundra	12.0	0.58	0.58	0.86	4.57	1.26	5.39
Isabella	Tungsten	12.0	0.52	0.73	0.76	3.87	1.08	4.72
Aqueduct	Tunnel	12.0	0.95	1.38	1.41	6.92	2.12	8.94
Peyton	Tupelo	12.0	0.22	0.42	0.29	2.46	0.48	3.42
Aqueduct	Turbine	12.0	0.82	1.04	1.20	5.47	2.04	6.89
Arcadia	Turf	4.16	0.07	0.10	0.10	0.60	0.17	0.71
Ordway	Turkey	12.0	0.16	0.32	0.22	1.60	0.41	2.12
Moreno	Turmeric	12.0	0.31	0.41	0.47	3.57	0.52	3.92
Walnut	Turnbull	12.0	0.56	0.90	0.76	3.94	1.24	5.53
Tulare	Turner	12.0	0.81	1.32	1.06	5.63	2.01	7.62
Aqueduct	Turnout	12.0	0.96	1.34	1.43	6.70	1.92	7.85
Santa Barbara	Turnpike	16.0	0.86	1.46	1.20	7.16	1.86	8.43
Bloomington	Turntable	12.0	1.07	1.33	1.64	7.11	2.15	8.15
Cabrillo	Turtle	12.0	0.20	0.36	0.11	4.65	0.19	5.64
Apple Valley	Tussing	12.0	0.45	0.75	0.65	3.69	0.94	4.94
Palmdale	Twain	12.0	0.42	0.59	0.60	3.03	0.90	3.89
Lynwood	Tweedy	4.16	0.10	0.15	0.15	0.93	0.17	1.03
Santa Monica	Twentysixst	4.16	0.10	0.18	0.15	0.96	0.20	1.04
Twenty Three St.	Twentythreest	4.16	0.00	0.02	0.00	0.10	0.00	0.16
Colorado	Twentytwost	4.16	0.00	0.01	0.00	0.10	0.00	0.14
Venice Hill	Twinbutte	12.0	0.47	0.70	0.63	4.30	0.93	5.09
Jersey	Twining	16.0	0.74	0.98	1.18	6.39	1.35	6.98
Santa Susana	Twinlakes	16.0	0.55	0.79	0.90	5.94	1.12	8.11

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Burnt Mill	TwinPeaks	33.0	0.00	0.01	0.00	0.08	0.00	0.08
La Habra	Twister	12.0	0.59	1.11	0.87	5.60	1.25	6.51
Tyburn P.T.	Tyburn	4.16	0.03	0.10	0.02	0.39	0.04	0.70
Puente	Tyhard	12.0	1.59	2.18	4.20	13.27	9.11	23.35
Amador	Tyler	4.16	0.17	0.29	0.24	1.51	0.32	1.81
Yorba Linda	Typhoon	12.0	0.73	1.20	0.99	5.21	2.13	7.74
Porterville	Ulmer	4.16	0.01	0.03	0.02	0.13	0.03	0.18
Mt. Tom	Underwood	12.0	0.73	1.22	1.07	5.65	1.41	6.70
Styx P.T.	Underworld	12.0	0.21	0.27	0.30	1.36	0.53	1.75
San Bernardino	Unicorn	12.0	0.82	1.59	1.24	8.17	1.57	8.69
Santa Fe Springs	Union	12.0	0.56	0.66	0.87	4.17	1.09	4.41
Bandini	Unionpacific	16.0	0.85	1.17	1.40	8.35	1.53	9.19
Rivera	Unity	4.16	0.06	0.05	0.08	0.68	0.09	0.71
Bassett	Unruh	12.0	0.89	1.15	1.34	6.80	1.83	7.99
Cucamonga	Unser	12.0	0.48	0.74	0.66	3.81	1.13	5.12
Camden	Uranium	12.0	0.40	0.71	0.55	4.18	0.70	5.17
Homart	Urbita	12.0	0.20	0.71	0.25	3.40	0.35	5.32
Twentynine Palms	Utah	12.0	0.38	0.80	0.58	3.71	0.64	4.81
Goldhill	Ute	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Nogales	Utopia	12.0	0.49	0.59	0.75	3.40	1.00	3.95
Borrego	Vaca	12.0	0.15	0.21	0.17	2.10	0.22	2.30
Shuttle	Vadar	12.0	0.68	0.95	0.95	4.42	1.52	5.87
Delano	Valente	12.0	1.02	1.37	1.62	10.01	1.83	11.23
Valentine P.T.	Valentine	2.4	0.00	0.01	0.00	0.04	0.00	0.06
Nogales	Valiant	12.0	0.87	0.96	1.14	5.14	2.25	7.59
Puente	Valinda	12.0	0.47	1.02	0.70	5.83	0.79	7.77
Carpinteria	Vallecito	16.0	0.75	1.69	0.99	8.89	1.31	11.09
Valley Of The Moon P.T.	Valleyofthemoon	2.4	0.04	0.19	0.06	3.68	0.06	7.06
Palos Verdes	Valmonte	4.16	0.02	0.05	0.02	0.57	0.02	0.89
Anita	Valnett	4.16	0.10	0.12	0.11	0.63	0.32	1.15
Bassett	Valsun	12.0	0.84	1.07	1.31	5.87	1.70	6.60
Ditmar	Valve	16.0	0.86	1.41	1.07	8.08	1.52	9.89
Saugus	Valverde	16.0	0.90	1.25	1.46	8.26	1.57	8.87
Brookhurst	Vanbrocklin	12.0	0.60	0.86	1.09	5.22	1.56	5.89
Atwood	Vanburen	12.0	0.61	0.96	1.13	6.06	1.89	7.79
Pico	Vancamp	12.0	0.07	0.17	0.12	1.09	0.13	1.29
Amalia	Vancouver	4.16	0.21	0.31	0.28	1.38	0.47	1.74
Porterville	Vandalia	12.0	0.64	0.87	0.90	3.90	1.59	5.26
Vanderlip P.T.	Vanderlip	2.4	0.00	0.00	0.00	0.04	0.00	0.06
Estero	Vanguard	16.0	0.08	0.12	0.13	0.89	0.14	0.93
Howard	Vanwick	4.16	0.19	0.25	0.28	1.66	0.33	1.95
Potrero	Vaquero	16.0	1.61	2.04	2.52	10.77	3.10	11.56
Lafayette	Vardon	12.0	0.67	0.94	1.06	5.28	1.24	5.60
Shandin	Vargas	12.0	0.16	0.64	0.19	2.76	0.27	4.61
Shandin	Varsity	12.0	0.39	0.86	0.59	5.86	0.69	6.57
Cabrillo	Vasco	12.0	0.78	1.96	1.27	11.67	1.28	12.03
Solemint	Vasquez	16.0	0.21	0.81	0.24	3.86	0.35	6.23
Corona	Vassal	12.0	0.33	0.45	0.52	3.31	0.63	3.78
Cortez	Vecino	12.0	0.87	1.08	1.22	4.95	2.03	6.40
Moraga	Velardo	12.0	0.20	0.52	0.23	2.76	0.36	4.15
Eisenhower	Vella	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Amador	Velma	16.0	0.30	0.55	0.44	2.85	0.61	3.32
Bluff Cove	Venus	4.16	0.14	0.01	0.14	0.79	0.50	1.34
Brea	Veracruz	12.0	0.45	0.73	0.72	4.82	1.02	6.01
Barre	Verbena	12.0	0.69	1.17	1.00	6.63	1.39	7.72
Hedda	Verde	4.16	0.17	0.22	0.24	1.00	0.44	1.32
Calectric	Verdemont	33.0	0.81	1.26	2.91	5.98	7.65	13.39
Padua	Verdi	12.0	0.54	0.85	0.71	4.18	1.64	6.60
La Canada	Verdugo	16.0	0.32	0.63	0.39	3.45	0.58	4.35
Windsor Hills	Verdun	4.16	0.09	0.31	0.13	1.33	0.14	2.09
Carolina	Vermont	12.0	0.30	0.67	0.38	3.55	0.54	4.78
Amalia	Verona	4.16	0.17	0.30	0.24	1.45	0.36	1.68
San Fernando	Veterans	16.0	0.43	0.51	0.66	2.85	0.90	3.17
Stoddard	Viaduct	4.16	0.06	0.12	0.09	0.65	0.11	0.75
Via Huerto P.T.	Viahuerto	4.16	0.02	0.04	0.04	0.32	0.04	0.48
Moraga	Vianorte	12.0	0.68	1.44	1.06	8.24	1.27	9.01
Cortez	Viaverde	12.0	0.66	1.02	0.84	4.80	2.07	7.82
Valdez	Vicasa	16.0	0.76	1.37	0.97	6.41	2.06	10.00
Corona	Vicentia	12.0	0.81	1.12	1.29	9.50	1.44	11.22

Substation	Distribution Circuit	Voltage (kV)	Scenario 1 Coincident Capacity (MW)	Scenario 1 Total Capacity (MW)	Scenario 2 Coincident Capacity (MW)	Scenario 2 Total Capacity (MW)	Scenario 3 Coincident Capacity (MW)	Scenario 3 Total Capacity (MW)
Passons	Vicki	12.0	0.43	0.94	0.61	5.43	0.78	6.90
Eaton	Video	16.0	0.21	0.48	0.30	2.65	0.44	3.39
Monolith	Viento	12.0	0.73	1.16	1.04	5.75	1.46	7.35
Lakewood	Viking	4.16	0.05	0.09	0.01	0.93	0.08	1.49
Perry	Villa	4.16	0.04	0.01	-0.01	0.90	0.01	0.95
Euclid	Village	4.16	0.06	0.06	0.08	0.51	0.12	0.60
Farrell	Viminal	12.0	0.46	0.72	0.67	3.45	1.17	4.81
Moraga	Vine	12.0	0.46	0.55	0.71	3.51	0.85	3.86
Saticoy	Vineyard	16.0	0.58	1.09	0.67	7.89	0.93	9.11
Rolling Hills	Violet	4.16	-0.01	0.05	-0.06	0.52	-0.06	0.92
Niguel	Violin	12.0	0.43	0.94	0.58	5.11	0.76	5.73
Gisler	Viper	12.0	0.88	1.22	1.32	5.91	1.91	6.84
Chatham	Virgil	12.0	0.47	0.77	0.65	3.94	0.90	5.48
Estrella	Virgo	12.0	0.75	0.92	1.22	8.66	1.27	10.86
Industry	Vise	12.0	1.02	1.23	1.61	8.64	1.89	9.46
Brewster	Vita	4.16	0.13	0.20	0.20	1.44	0.24	1.52
Timoteo	Vitamin	12.0	0.52	1.02	0.78	5.55	0.95	6.11
Vogan P.T.	Vogan	4.16	0.02	0.05	0.03	0.32	0.03	0.39
Liberty	Volney	12.0	0.28	0.69	0.40	3.21	0.64	4.34
Farrell	Volturno	12.0	0.62	0.93	0.90	4.35	1.55	6.07
Dalton	Von	12.0	1.08	1.44	1.72	13.12	1.88	15.46
Fullerton	Voni	4.16	0.00	0.01	0.00	0.04	0.00	0.07
Yorba Linda	Vortex	12.0	0.44	0.66	0.63	3.96	0.96	4.79
Woodville	Vossler	12.0	0.24	0.29	0.36	1.85	0.55	2.31
Gisler	Voyager	12.0	0.75	0.93	1.18	5.84	1.28	6.25
Casa Diablo	Vulcan	33.0	0.00	0.00	0.00	0.00	0.00	0.00
Imperial	Vultair	12.0	0.67	0.92	1.00	5.17	1.23	6.07
Lennox	Vultee	16.0	1.06	1.33	1.63	7.30	2.13	7.96
Trask	Waco	12.0	0.46	0.65	0.62	2.95	1.02	4.06
Ocean Park	Wadsworth	4.16	0.11	0.14	0.15	1.01	0.18	1.18
Howard	Wagner	4.16	0.16	0.24	0.24	1.52	0.27	1.65
Randall	Wahlstrom	12.0	0.48	0.87	0.73	5.23	0.91	6.22
Nogales	Wahoo	12.0	0.75	0.64	1.03	4.83	1.87	6.43
MacArthur	Wainwright	12.0	0.48	1.06	0.75	6.11	0.82	6.32
Skylark	Waite	12.0	0.26	0.54	0.33	3.01	0.60	4.50
Marine	Walgrove	16.0	0.60	0.65	0.94	3.90	1.07	4.11
Delano	Wallace	12.0	0.62	1.10	0.87	4.50	1.35	6.56
Huntington Park	Walnutpark	4.16	0.14	0.18	0.22	1.23	0.24	1.35
Signal Hill	Walrus	12.0	0.62	0.77	0.97	4.21	1.16	4.44
Stewart	Walter	12.0	1.10	1.24	1.70	10.71	2.21	12.75
Sunnyside	Wanda	12.0	0.38	0.53	0.59	3.17	0.77	3.70
Fair Oaks	Wapello	4.16	0.11	0.09	0.11	0.64	0.35	1.12
Longdon	Ward	4.16	0.10	0.12	0.15	0.96	0.18	1.00
Newcomb	Wardell	12.0	0.33	0.62	0.46	3.90	0.66	5.06
Los Cerritos	Wardlow	4.16	0.17	0.26	0.23	1.25	0.38	1.52
Kimball	Warhawk	12.0	0.37	0.66	0.52	3.27	0.80	4.26
Randolph	Warman	16.0	0.41	0.52	0.59	2.39	0.87	2.99
Cardiff	Warmcreek	12.0	0.89	1.13	1.45	7.11	1.52	7.48
Bedford	Warner	4.16	0.10	0.19	0.15	1.03	0.20	1.14
Team	Warriors	12.0	1.15	1.44	1.74	8.04	2.28	9.17
Sangar	Warwick	4.16	0.12	0.08	0.14	0.74	0.44	1.27
Rio Hondo	Wash	16.0	0.69	0.91	0.97	6.70	1.17	7.11
Vegas	Wasp	16.0	1.39	1.66	2.15	10.65	2.64	11.69
Brookhurst	Waterfield	12.0	0.48	0.59	0.63	3.75	1.00	4.99
Cardiff	Waterman	12.0	0.62	0.77	0.93	3.78	1.39	4.42
North Intake	Waterwheel	12.0	0.04	0.07	0.06	0.32	0.10	0.43
Graham	Watts	4.16	0.06	0.09	0.09	0.60	0.10	0.68
Bovine	Watusi	12.0	1.00	1.16	1.49	6.13	2.20	7.14
Hanford	Wayne	4.16	0.02	0.04	0.03	0.05	0.07	0.16
Fremont	Wayside	16.0	0.58	0.75	0.92	5.59	1.04	6.36
Basta	Wealth	4.16	0.05	0.06	0.06	0.67	0.07	0.73
Hoyt	Weaver	4.16	0.12	0.20	0.18	1.09	0.21	1.33
Oak Grove	Webb	12.0	0.78	1.01	1.23	6.17	1.39	6.38
South Gate	Webbwood	4.16	0.18	0.27	0.26	1.66	0.30	1.83
Ganesha	Weber	4.16	0.09	0.14	0.12	0.73	0.25	1.06
State Street	Webster	12.0	0.96	1.62	1.33	7.84	2.05	8.98
Defrain	Wedge	12.0	0.09	0.20	0.14	0.87	0.17	1.19
Narod	Weeks	12.0	1.05	1.52	1.49	6.87	2.57	8.58
Weesha P.T.	Weesha	2.4	0.00	0.00	0.00	0.02	0.00	0.03

Substation	Distribution Circuit	Voltage (kV)	Scenario 1 Coincident Capacity (MW)	Scenario 1 Total Capacity (MW)	Scenario 2 Coincident Capacity (MW)	Scenario 2 Total Capacity (MW)	Scenario 3 Coincident Capacity (MW)	Scenario 3 Total Capacity (MW)
Canyon	Weir	12.0	0.38	0.73	0.58	4.47	0.67	4.90
Chase	Weirick	12.0	0.52	0.92	0.80	5.73	1.02	6.65
Alon	Weiser	12.0	0.28	0.45	0.44	3.65	0.48	4.07
Lafayette	Weiskoff	12.0	1.04	1.23	1.57	7.00	2.19	7.96
Bryman	Weiss	4.16	0.04	0.08	0.05	0.32	0.07	0.47
Vestal	Welch	12.0	0.54	0.67	0.83	5.08	1.08	6.25
Palm Village	Welcome	4.8	0.11	0.17	0.15	0.67	0.31	1.07
Venida	Wells	12.0	0.54	0.89	0.74	4.22	1.43	5.49
Covina	Werden	4.16	0.09	0.14	0.12	0.71	0.25	1.04
Culver	Wesley	4.16	0.00	-0.05	-0.08	0.56	-0.06	0.80
Maxwell	Westbluff	12.0	0.42	0.69	0.56	3.53	1.06	5.02
Murrietta	Westbrook	12.0	0.35	0.62	0.47	2.35	0.90	3.41
Delano	Westcity	4.16	0.02	0.03	0.04	0.17	0.06	0.21
Westend P.T.	Westend	12.0	0.00	0.01	0.00	0.03	0.01	0.04
Yukon	Western	16.0	0.37	0.44	0.57	2.89	0.72	3.32
Westfall P.M.	Westfall	4.16	0.00	0.00	-0.05	0.49	-0.05	0.79
Westfall P.M.	Westfallp.T.	4.16	0.00	0.00	0.00	0.00	0.00	0.00
Bassett	Westfield	12.0	0.44	0.56	0.68	2.93	0.85	3.25
Westmont P.T.	Westmont	4.16	0.00	0.02	0.00	0.12	0.00	0.15
Earlimart	Weston	12.0	0.28	0.36	0.42	2.40	0.59	2.87
Olympic	Wetherly	4.16	0.09	0.13	0.12	0.78	0.19	0.97
El Nido	Whale	16.0	0.55	1.01	0.81	5.34	0.98	5.72
Tulare	Whey	12.0	0.46	1.00	0.64	4.54	1.26	6.31
Quartz Hill	Whip	12.0	0.46	1.00	0.60	4.45	1.02	6.92
Olinda	Whipstock	12.0	0.34	0.51	0.42	2.38	1.10	4.05
Chiquita	Whiskey	12.0	0.09	0.63	0.00	3.13	0.11	5.91
Chase	Whisper	12.0	0.67	0.87	1.08	7.70	1.16	8.81
La Palma	Whitaker	12.0	0.37	0.67	0.54	3.73	0.72	4.13
Longdon	White	4.16	0.12	0.16	0.18	0.98	0.31	1.14
Thousand Oaks	Whitecliff	16.0	0.37	0.70	0.38	3.96	0.95	6.39
Joshua Tree	Whitehorn	12.0	0.26	0.30	0.37	1.62	0.67	2.12
Milliken	Whitehorse	12.0	0.75	1.03	1.20	6.82	1.30	7.30
Oak Grove	Whitendale	12.0	0.46	0.75	0.64	3.52	1.28	4.41
Wabash	Whiteside	16.0	0.27	0.45	0.41	3.43	0.47	3.85
Sepulveda	Whiting	16.0	0.32	0.47	0.52	2.94	0.53	3.11
Tippecanoe	Whitlock	4.16	0.04	0.08	0.06	0.46	0.08	0.56
Rosemead	Whitmore	16.0	0.50	0.96	0.73	5.45	0.93	6.29
Calden	Whitsett	16.0	0.14	0.27	0.20	1.44	0.26	1.67
Declez	Whittram	4.16	0.05	0.10	0.08	0.61	0.11	0.76
Friendly Hills	Whittwood	4.16	0.07	0.10	0.08	0.81	0.14	1.08
Beverly	Whitworth	16.0	0.16	0.33	0.25	1.90	0.28	1.98
Malibu	Whizzin	16.0	0.18	0.33	0.16	2.05	0.44	3.28
Trask	Wichita	12.0	0.46	0.56	0.71	3.24	0.91	3.59
Camarillo	Wigton	16.0	0.68	0.67	0.97	4.52	1.60	5.64
Bloomington	Wigwag	12.0	0.29	0.50	0.36	3.36	0.62	4.68
Laurel	Wilbur	12.0	0.50	0.61	0.74	3.80	1.19	4.86
Cudahy	Wilcox	16.0	0.76	1.03	1.21	8.08	1.38	9.53
Bullis	Wildcat	16.0	0.46	0.75	0.62	3.66	0.87	4.51
Wilderness P.T.	Wilderness	2.4	0.00	0.00	0.00	0.00	0.00	0.00
Mariposa	Wildflower	12.0	0.08	0.09	0.12	0.64	0.16	0.72
Elsinore	Wildomar	33.0	0.00	0.00	0.00	0.01	0.00	0.01
Newhall	Wildwood	16.0	0.20	0.68	0.09	4.25	0.28	6.86
Newhall	Wiley	16.0	0.38	0.67	0.47	4.14	0.81	5.59
Ravendale	Willard	16.0	0.89	1.66	1.18	8.32	1.73	10.12
Sullivan	Willets	12.0	0.45	0.69	0.63	4.40	0.75	5.02
Stewart	William	12.0	1.18	1.50	1.82	8.49	2.41	9.75
Upland	Willis	12.0	0.71	0.85	1.04	4.40	1.61	5.51
Watson	Willow	12.0	0.45	0.79	1.22	4.12	2.76	7.68
Rosamond	Willowsprings	12.0	0.09	0.12	0.16	0.96	0.25	1.35
Ramona	Wilmar	4.16	0.07	0.10	0.10	0.83	0.12	0.93
Alon	Wilmington	12.0	0.09	0.16	0.13	1.20	0.14	1.50
Beverly	Wilshire	4.16	0.07	0.10	0.11	0.56	0.13	0.59
Yucaipa	Wilsoncreek	12.0	0.34	0.52	0.90	4.21	2.01	6.16
Dalton	Winark	12.0	0.66	0.78	1.02	5.49	1.31	6.52
Pico	Windham	12.0	0.02	0.07	0.03	1.33	0.04	2.52
Winding P.T.	Winding	4.16	0.03	0.05	0.03	0.39	0.07	0.60
Channel Island	Windjammer	16.0	0.79	1.47	1.04	8.72	1.37	9.83
Laurel	Windt	12.0	0.56	0.77	0.85	5.78	1.06	7.02
Alder	Windtunnel	12.0	0.56	0.87	1.01	5.61	1.59	6.81

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Pauba	Winery	12.0	0.29	0.67	0.41	3.15	0.68	4.60
Pedley	Wineville	12.0	0.64	1.02	0.85	6.45	1.21	7.63
Gonzales	Winford	16.0	2.07	2.28	3.21	13.58	3.84	15.25
Savage	Wing	12.0	0.58	0.68	0.89	3.96	1.19	4.59
MacArthur	Wingate	12.0	0.56	1.32	0.89	7.58	0.99	7.96
Chestnut	Wingnut	12.0	0.28	0.53	0.42	3.16	0.48	3.63
Rolling Hills	Winlock	16.0	0.24	0.42	0.36	2.49	0.40	2.70
West Riverside	Winnebago	12.0	0.49	0.62	0.74	3.65	1.12	4.22
Trophy	Winner	12.0	0.58	0.72	0.90	5.44	1.10	6.66
Bullis	Winona	16.0	0.99	1.33	1.56	9.17	1.90	10.46
Belding	Winterhaven	4.16	0.11	0.27	0.16	1.06	0.28	1.83
Dunes	Winters	12.0	0.10	0.14	0.15	0.95	0.16	0.97
Oceanview	Wintersburg	12.0	0.95	1.10	1.37	6.13	1.98	7.36
Live Oak	Winthrop	12.0	0.62	0.73	0.84	4.11	1.83	5.36
Carolina	Wisconsin	12.0	0.23	0.48	0.28	2.95	0.53	4.37
Davidson City	Wise	4.16	0.17	0.28	0.22	1.59	0.29	1.97
Anita	Wistaria	4.16	0.02	0.16	0.01	0.83	0.01	1.44
Lucas	Wolf	12.0	0.31	0.49	0.34	3.88	0.52	4.34
Cathedral City	Wonderpalms	4.8	0.12	0.15	0.20	1.33	0.23	2.07
Oak Park	Woodhaven	16.0	0.38	0.32	0.47	2.36	1.05	3.55
Liberty	Woodland	12.0	0.48	1.13	0.66	5.29	1.04	6.81
Colonia	Woodroad	16.0	0.00	0.00	0.00	0.00	0.00	0.00
Belmont	Woodrow	4.16	0.10	0.16	0.14	0.95	0.17	1.09
Badillo	Woodside	4.16	0.12	0.21	0.18	1.08	0.33	1.48
Peyton	Woodview	12.0	0.62	0.80	0.85	4.88	1.68	6.53
Alhambra	Woodward	4.16	0.07	0.13	0.10	0.70	0.14	0.81
Shuttle	Wookie	12.0	0.75	1.10	1.10	5.33	1.42	6.20
Michillinda	Woolley	4.16	0.04	0.09	0.01	0.63	0.05	1.00
Porterville	Worth	12.0	1.38	1.89	3.56	10.19	8.06	17.81
Pebbly Beach	Wrigley	12.0	0.00	0.50	0.00	2.49	0.00	2.76
Rector	Wutchumna	12.0	0.35	0.76	0.50	3.49	0.81	5.21
Chase	Wyle	12.0	0.66	1.11	0.91	5.93	1.58	8.08
Carolina	Wyoming	12.0	0.20	0.57	0.20	3.60	0.26	5.32
Cabrillo	Xerox	12.0	0.28	0.66	0.44	3.77	0.49	3.96
Hathaway	Ximeno	12.0	0.20	0.51	0.31	2.95	0.35	3.13
Johanna	Yahtzee	12.0	0.51	0.75	0.76	5.30	0.98	6.26
Colorado	Yale	4.16	0.03	0.03	0.03	0.32	0.04	0.36
Yankee P.T.	Yankee	2.4	0.00	0.01	0.01	0.03	0.01	0.03
Cucamonga	Yarborough	12.0	0.94	1.25	1.50	7.92	1.63	9.34
Vail	Yates	16.0	0.93	1.12	1.42	7.07	1.95	8.43
Orange	Yellow	12.0	0.39	0.65	0.54	3.14	0.88	3.95
Riverway	Yellowstone	12.0	0.37	0.95	0.51	4.11	0.90	6.05
Bayside	Yellowtail	12.0	0.49	1.35	0.63	6.65	0.78	9.28
Santiago	Yen	12.0	0.72	1.42	1.13	8.82	1.24	9.56
Newmark	Ynez	4.16	0.16	0.20	0.22	1.35	0.36	1.67
Shuttle	Yoda	12.0	0.72	0.90	1.00	3.64	2.00	5.10
Hamilton	Yogi	12.0	0.12	0.42	-0.07	3.69	0.08	5.58
Perez	Yorba	4.16	0.09	0.13	0.13	0.80	0.18	0.93
Yukon	York	4.16	0.05	0.07	0.07	0.49	0.09	0.53
Narrows	Yorktown	12.0	0.48	0.95	0.63	5.20	0.88	6.55
Santa Susana	Yosemite	16.0	0.77	1.20	1.11	6.19	1.60	8.00
Beverly	Young	16.0	0.16	0.36	0.24	2.00	0.27	2.16
Brookhurst	Younger	12.0	0.61	0.96	0.86	6.52	1.00	7.52
Chino	Younkin	12.0	0.62	0.78	0.96	5.23	1.23	6.24
Coffee	Yuban	12.0	0.67	0.96	1.01	5.08	1.24	5.92
Brea	Yucatan	12.0	0.56	0.98	0.78	5.15	1.24	6.40
Lancaster	Yucca	4.16	0.16	0.19	0.21	0.62	0.42	0.94
Rancho	Yuccaloma	12.0	0.25	0.32	0.40	2.74	0.44	3.95
Sullivan	Yuma	12.0	0.06	0.24	0.09	1.36	0.12	1.46
Fremont	Zamora	16.0	0.71	0.94	1.12	7.45	1.36	8.93
Sunnyside	Zane	12.0	0.71	0.93	1.04	5.28	1.55	6.39
Maxwell	Zantar	12.0	0.41	0.71	0.58	3.43	1.11	4.83
Strathmore	Zante	12.0	0.27	0.68	0.35	3.04	0.55	4.08
Cardiff	Zapata	12.0	0.47	0.60	0.72	3.47	1.00	3.88
Quartz Hill	Zappa	12.0	0.44	0.75	0.62	3.35	1.11	4.84
Victor	Zasadni	12.0	0.51	0.61	0.72	3.10	1.41	4.56
El Nido	Zebra	16.0	1.00	1.24	1.53	6.46	2.07	7.08
Bovine	Zebu	12.0	0.99	1.22	1.55	7.55	1.86	8.14
Loraine	Zenda	12.0	0.08	0.13	0.10	0.52	0.17	0.77

			Scenario 1		Scenario 2		Scenario 3	
Substation	Distribution Circuit	Voltage (kV)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)	Coincident Capacity (MW)	Total Capacity (MW)
Carson	Zeno	16.0	0.62	0.83	1.00	7.02	1.08	8.27
Walteria	Zepher	16.0	0.43	0.69	0.65	4.53	0.84	5.10
Nola	Zeppelin	16.0	0.57	0.74	0.91	4.52	1.04	4.83
Proctor	Zeus	12.0	3.52	5.30	11.10	28.38	27.06	62.99
Murrietta	Zevo	12.0	0.49	0.82	0.70	3.82	1.05	4.36
Ziggy P.T.	Ziggy	12.0	0.00	0.01	0.00	0.06	0.00	0.06
Randall	Zimmer	12.0	0.34	0.56	0.53	4.14	0.65	5.10
Crest	Zinc	16.0	0.06	0.08	-0.14	2.74	-0.09	4.13
Pepper	Zinfandel	12.0	0.42	0.93	0.63	5.11	0.72	6.08
Archline	Zinser	12.0	0.51	1.03	0.76	5.67	1.05	6.91
Terra Bella	Zion	12.0	0.62	1.02	0.90	5.80	1.13	6.57
Stetson	Zippy	12.0	0.29	0.44	0.44	2.93	0.67	3.44
Crest	Zircon	16.0	0.77	1.06	1.19	5.45	1.50	5.84
Estrella	Zodiac	12.0	0.63	1.50	1.02	9.99	1.04	11.58
Randolph	Zoe	16.0	0.36	0.47	0.54	2.32	0.76	2.81
Moorpark	Zone	16.0	0.48	0.53	0.71	5.09	0.86	5.64
Victor	Zuni	33.0	0.00	0.00	0.00	0.00	0.00	0.00